# Best Available Retrofit Technology Determination

BP Cherry Point Refinery

Blaine, Washington

*Prepared for:*

**BP Cherry Point Refinery**
4519 Grandview Road
Blaine, Washington 98230

March 2008

Project No. 012966.000.0

Geomatrix

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# BEST AVAILABLE RETROFIT TECHNOLOGY DETERMINATION

BP Cherry Point Refinery
Blaine, Washington

## 1.0 INTRODUCTION

EPA published Best Available Retrofit Technology (BART) regulations on July 6, 2005 pursuant to the Regional Haze Rule. BART requirements apply to industrial sources with emissions of an individual visibility-affecting air pollutant exceeding 250 tons per year from emission units that were constructed between August 7, 1962 and August 7, 1977. The visibility-affecting pollutants are nitrogen oxides (NOx); sulfur dioxide (SO2); particulate matter (PM) including particulate matter with aerodynamic diameter less than 10 microns (PM10) and with aerodynamic diameter less than 2.5 microns (PM2.5); volatile organic compounds (VOC); and ammonia. The Washington Department of Ecology (Ecology) has determined that VOC emissions from the Cherry Point Refinery do not need to be considered because the BART-eligible sources at the Refinery do not have actual VOC emissions greater than 250 tons per year. Furthermore, Ecology has not identified ammonia as a pollutant of concern; therefore, ammonia does not need to be included in the analysis.

According to 40 CFR Part 51.308(e), the State must submit an implementation plan containing emission limitations representing BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I area. To help identify the BART-eligible sources and to determine the level of control technology that represents BART, EPA published BART determination guidelines in 40 CFR 51, Appendix Y. Ecology identified the potential BART sources and sent letters to each facility with BART-eligible sources indicating their BART-eligible status and pollutants of concern. Facilities with BART-eligible sources are responsible for completing BART technology analyses.

Because BP's Cherry Point Refinery operates equipment of the applicable age and emits more than 250 tons of a visibility-affecting pollutant, it is potentially subject to the BART program and received a letter indicating its potential BART-eligible status. Using the guidelines in 40 CFR 51 Appendix Y, this document presents the BART technology analysis for each BART-eligible source at the BP Cherry Point Refinery. This report provides the rationale for selecting the proposed BART technology, background information supporting the selection, and the proposed BART emission limitation for each source.

BP retained Geomatrix Consultants, Inc. (Geomatrix) to provide regulatory guidance, dispersion modeling support, and report preparation. Jacobs Engineering (Jacobs) was contracted to perform the engineering analyses and budgetary cost estimates for the potential BART control options.

## 1.1 BART-ELIGIBLE SOURCES

Ecology compiled and transmitted a list of potential BART-eligible sources for the Cherry Point Refinery. BART-eligible units that have been reconstructed, removed, or replaced since August 7, 1977 can be eliminated from the analysis. However, those BART-eligible sources that have been modified (even with Best Available Control Technology [BACT]) – but not reconstructed – need to be included in the analysis.[1] For instance, the Boiler No. 2 has been replaced and therefore is not considered in the analysis. The South Vacuum Heater, on the other hand, was modified and had BACT installed, but was not reconstructed, removed, and/or replaced; therefore, it remains in the analysis.

Several potential BART-eligible sources from the original Ecology list were excluded from the BART determination analysis for the following reasons:[2]

- #1 and #2 Calciners: The Notice of Construction was initially issued October 12, 1977 and revised November 17, 1977, after the BART-applicable time frame.
- #2 Reformer Heaters: Constructed in 1987, after the BART-applicable time frame.
- Floating Roof Storage Tanks: Negligible NOx, SO2, and PM10/PM2.5 emissions.
- Fixed Roof Storage Tanks: Negligible NOx, SO2, and PM10/PM2.5 emissions.
- Flare Gas Recovery: Not an emission unit.
- API (American Petroleum Institute) Separators: Negligible NOx, SO2, and PM10/PM2.5 emissions.
- LPG Loading Racks: Negligible NOx, SO2, and PM10/PM2.5 emissions.
- #1 Cooling Tower: No NOx or SO2 emissions. Particulate emissions in the cooling tower drift settle quickly and do not contribute to regional haze.

[1] 40 CFR Part 51 Appendix Y.II.A.2. "How are modifications treated under the BART provision?"
[2] Except for Boilers 1 and 3, these exclusions were approved by Alan Newman of the Department of Ecology in a February 7, 2007 letter to Valerie Lagen, BP Sr. Environmental Engineer. Since then, a federally-enforceable permit has been issued requiring that boilers 1 and 3 be removed prior to the startup of the two replacement boilers, #5 and #6

- Boiler No. 1: As part of the Boiler Replacement Project, BP has committed to decommissioning Boilers No. 1 and No. 3. As such, these units are no longer BART-eligible and are not addressed in this analysis.

- Boiler No. 2: The No. 2 Boiler was shut down in 2004 as part of the 2001 EPA Consent Decree NOx reduction requirements. As such, this unit is no longer BART- eligible and is not addressed in this analysis.

- Boiler No. 3: As part of the Boiler Replacement Project, BP has committed to decommissioning Boilers No. 1 and No. 3. As such, these units are no longer BART-eligible and are not addressed in this analysis.

Consistent with discussions with Ecology, 20 emission units at the Cherry Point Refinery are considered in this analysis as BART-eligible:

- Crude Heater
- South Vacuum Heater
- No. 1 Reformer Heaters
- Naphtha HDS Charge Heater
- Naphtha HDS Stripper Reboiler
- 1st Stage Hydrocracker Fractionator Reboiler
- 2nd State Hydrocracker Fractionator Reboiler
- R-1 Hydrocracker Reactor Heater
- R-4 Hydrocracker Reactor Heater
- North Coker Charge Heater (No. 1)
- South Coker Charge Heater (No. 2)
- Diesel HDS Charge Heater
- Diesel HDS Stabilizer Reboiler
- No. 1 Steam Reforming Furnace
- No. 2 Steam Reforming Furnace
- Low Pressure Flare

- High Pressure Flare
- SRU & TGU (Sulfur Incinerator)
- Green Coke Loadout
- South Dock

For easy cross-referencing, Table 1-1 lists the equipment numbers associated with each BART source from different references to relate the BART sources to the existing permitting history.

## 1.2 BART EXEMPTION ANALYSIS

If a facility with identified BART-eligible sources can demonstrate through dispersion modeling that the cumulative visibility impact of the facility's BART-eligible sources is less than a certain threshold at any Class I area, the facility is exempt from the BART program and does not have to meet the BART emission limitations and associated control requirements. Ecology established a facility-wide impact threshold of 0.5 deciviews (dv).

Preliminary modeling of the BART-eligible sources was conducted to determine if the BP Cherry Point Refinery qualifies for the BART program exemption. Emissions used in the modeling were based on the maximum 24-hour daily average for SO2, NOx, PM10, and PM2.5 from the 2003 to 2005 baseline. Projects that impacted NOx, $SO_2$, $PM_{10}$/PM2.5 emissions performed since 2005 were incorporated into the exemption modeling analysis. Based on this modeling, it was determined that the BP Cherry Point refinery does not qualify for the BART exemption and all the BART-eligible sources are subject to BART.

## 2.0 BART SELECTION PROCESS

For each source subject to BART, the level of control representing BART must be determined. The method for this analysis follows the Federal guidance provided in 40 CFR 51 Appendix Y, the Department of Ecology Best Available Retrofit Technology Determinations under the Federal Regional Haze Rule issued June 12, 2007 ("Ecology's Guidance"), and subsequent Ecology direction as outlined in this report.

The best system of continuous control technology for each source must be identified taking into account:

- the technology available,
- the costs of compliance,
- the energy and non-air quality environmental impacts of compliance,
- any pollution control equipment in use at the source,
- the remaining useful life of the source, and
- the degree of visibility improvement that may be expected from available control technology.

Once the level of control representing BART has been identified, the BART sources must establish a BART emission limit and must ensure compliance with that requirement no later than five years after the State Implementation Plan (SIP) is approved. As of this writing, the SIP is expected to be submitted in early 2009; review by EPA could take a year or more.

### 2.1 STEP 1: IDENTIFICATION OF ALL AVAILABLE RETROFIT EMISSION CONTROL TECHNIQUES

Available retrofit control options are those air pollution control technologies with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered. Also, it is not necessary to consider control technologies that require redesign of the source or require that the source be de-rated. These are important qualifiers because several of the control options that might potentially apply to BP emission units would re-rate the unit.

Generally, control alternatives can fall into three categories:

- Pollution prevention – use of lower-emitting processes/practices including use of control techniques (e.g., low-NOx burners) and work practices that prevent emissions and result in lower "production-specific" emissions
- Use of and, if applicable, improvement of add-on controls
- Combinations of inherently lower-emitting processes and add-on controls

Potential available technology options can be drawn from BACT or Lowest Achievable Emission Rate (LAER) determinations, New Source Performance Standards (NSPS) control requirements, control technology vendors, and EPA publications, among other sources. The control technologies considered must represent the full range of demonstrated alternatives.

If a BART unit already has the most stringent available control installed, no additional BART analysis is necessary as long as the control is federally enforceable,.

## 2.2 STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Control technologies may be eliminated from the list compiled in Step 1 by demonstrating that they are technically infeasible. To claim a control technology is technically infeasible, a discussion must be provided documenting the technical difficulties based on physical, chemical, or engineering principles that would preclude the successful use of the control option. BP also considered technologies that pose safety issues to be technically infeasible. In addition, refinery process units are only taken down for significant maintenance in a cycle-ending turnaround (TAR) once every five years. As such, control equipment that would require process equipment to shut down for maintenance more often than during the cycle ending turnarounds every three to five years was considered technically infeasible.

Technical feasibility is based on the availability and applicability of the control technology. Available technologies are those that have reached the stage of licensing and commercial availability by the close of the public comment period for the State Implementation Plan (SIP). Applicable technologies are those that are commercially available that have been used successfully on the same or similar source type.

A demonstration of technical infeasibility may involve showing that there are unresolvable technical difficulties with applying the control to the source (e.g., size of the unit, location of the proposed site, operating problems related to specific circumstances of the source, space

constraints, reliability, and adverse side effects on the rest of the facility). However, where the resolution of technical difficulties is merely a matter of increased cost, the technology is still considered technically feasible.

## 2.3 STEP 3: EVALUATE CONTROL EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

Comparing the control effectiveness among feasible technologies must be done using a metric that ensures a fair comparison among options, such as an average steady state emissions level per unit of product produced or processed (e.g., pounds of SO2 per MMBtu). Also, the performance of control technologies over a wide range of emission performance levels must be considered as well.

When evaluating control options, the most stringent option (i.e., the greatest control that the technology is capable of achieving) must be considered. Less stringent levels of control can be considered as additional options.

## 2.4 STEP 4: EVALUATE IMPACTS AND DOCUMENT THE RESULTS

This analysis includes four aspects: (1) Costs of Compliance, (2) Energy Impacts, (3) Non-Air Quality Environmental Impacts, and (4) Remaining Useful Life. Ecology also requested that collateral increases in emissions be addressed.

### 2.4.1 Costs of Control

The cost effectiveness of various control options is based on the relative costs and degree of control of BART "baseline" emissions. Ecology guidance indicates the baseline period for cost-effectiveness calculations is the average actual emissions over the two-year period preceding the BART analysis. However, with the number of heaters subject to BART and the complexity of maintaining two sets of databases throughout the BART analyses, BP elected to apply the same baseline to the cost effectiveness calculations as applied to the visibility impact assessment for the heaters. That baseline is discussed in Section 2.5. This approach overstates control option cost-effectiveness for heaters because average emissions over a two-year period are obviously much lower than those derived by extrapolating maximum daily emissions over a three year period.

Ecology guidance also acknowledges that it is appropriate to adjust a unit's baseline emission rates to reflect the impact of recently installed modifications or emission control equipment that is not reflected in the baseline emissions.

The control cost analysis is based on the emission units being controlled, the design parameters for emission controls, and the cost estimates based on the design parameters. Therefore, the analysis should provide a clear summary list of equipment and associated control costs. In addition, the control system design parameters must be specified along with documentation of any assumptions made. The basis for capital and annual costs must be documented, either with data supplied by an equipment vendor or by a referenced source. To maintain consistency, the guidance recommends that the OAQPS Control Cost Manual be used as much as possible.[3] For this BART analysis, Jacobs was contracted to identify capital and operating costs based on their substantial experience in designing refinery process equipment; these data were input to the OAQPS cost effectiveness templates.

The control costs can be examined in two different ways: the cost effectiveness and the incremental cost effectiveness. The cost effectiveness is the total annualized costs of control divided by the annual emission reductions (i.e., $/ton):

$$\text{Cost effectiveness (\$/ton)} = \frac{\text{Total Annualized Costs of Control Option}}{(\text{Baseline Annual Emissions - Control Option Annual Emissions})}$$

Incremental cost effectiveness is used to compare the cost and performance level of a control option to the next most stringent option (i.e., how much it will cost per ton to obtain the next more stringent control). The incremental cost effectiveness is calculated as follows:

Incremental Cost Effectiveness ($/ton) =

$$\frac{(\text{Total Annualized Costs of Control Option - Total Annualized Costs of Next Control Option})}{(\text{Control Option Annual Emissions - Next Control Option Annual Emissions})}$$

This analysis focuses on annualized cost and emission reduction differences between those alternatives that provide the most efficient use of resources. Both the overall cost per ton and the incremental cost should be considered when making an overall cost-effectiveness finding.

The calculation of the annual emission reduction and "baseline" emissions for the BP Cherry Point refinery BART analysis is discussed in Appendix A.

[3] OAQPS Control Cost Manual, Fifth Edition, February 1996, EPA 453/B-96-001 or more recent version (http://www.epa.gov/ttn/catc/products.html#cccinfo)

### 2.4.2 Energy Impacts

The energy impacts, whether energy penalties or benefits, should be evaluated for each control option. Only direct energy consumption and not indirect energy impacts should be considered. Issues such as use of locally scarce fuels or whether a given alternative would result in significant economic disruption or unemployment can also be considered in the energy impact analysis. Because energy penalties or benefits can usually be quantified in terms of additional cost or income to the source, energy impacts are also be factored into the cost impacts analysis.

### 2.4.3 Non-Air Quality Environmental Impacts

An analysis of any environmental impacts other than air quality can be used to evaluate control options in a BART analysis. This can include, but is not limited to, solid or hazardous waste generation, discharges of polluted water from a control device, irreversible or irretrievable commitment of resources (e.g., use of scarce water resources), noise levels, radiant heat, or dissipated electrical energy.

### 2.4.4 Collateral Emissions Increases

Control technologies are used to reduce emissions of a specific pollutant. However, in so doing, emissions of other pollutants may increase or a new pollutant may be introduced. As part of this BART analysis, Ecology requested that collateral emissions increases be addressed.

### 2.4.5 Remaining Useful Life

The remaining useful life of the BART emission unit is taken into account in evaluating the control options when determining the annualized cost of the retrofit controls. In the OAQPS Control Cost Manual, calculating the annualized cost requires a specified time period for amortization, usually estimated at 20 years for new equipment.[4] If the remaining useful life will clearly exceed this time period, the remaining useful life has essentially no effect on control costs and on the BART determination process. Where the remaining useful life is less than the time period for amortizing costs, the shorter time period should be used in the cost calculations.

The remaining useful life is the difference between the date that controls will be put in place and the date the facility permanently stops operations, which should be ensured with a federally-enforceable restriction preventing further operation. If a source chooses not to accept a federally-enforceable condition to shut down by a given date (e.g., the facility wishes to keep

[4] OAQPS Control Cost Manual, Fifth Edition, February 1996, EPA 453/B-96-001, Section 1, Chapter 2, Table 2.3

a unit dormant in case market conditions change necessitating its use), the BART control level analysis should be based on the full operational remaining life of the unit. The resulting control level should be incorporated as a BART emission limit, which would serve as a contingency should the source continue operating more than five years after the date EPA approves the relevant SIP. The source would not be allowed to operate after the five-year mark without such controls. If a source does operate after the five-year mark without BART in place, the source is considered to be in violation of the BART emissions limit for each day of operation.

### 2.4.6 Selection of Best Alternative

When evaluating specific control options, the analysis must include: (1) expected emission rate, (2) emission performance level, (3) expected emission reduction, (4) cost of compliance (including annual and incremental costs and taking into account the remaining useful life), (5) energy impacts, (6) non-air quality environmental impacts, and (7) modeled visibility impacts. A justification for adopting the technology must be discussed along with an explanation of the factors that led to the selection of that option over the other options.

## 2.5 STEP 5: EVALUATE VISIBILITY IMPACTS

Once the potentially feasible control options have been evaluated, a visibility improvement determination must be conducted. Ecology requires that the CALPUFF dispersion model be used to model SO2, NOx, and direct particulate matter (PM2.5 and/or PM10) emissions in two scenarios: "Baseline" and "With BART."

Because the visibility impact criterion is a calendar day average, the BART program requires that modeling be done using the worst-case 24-hour emissions for the BART-eligible units. To establish the modeling Baseline emissions, Ecology requires the worst-case calendar day emissions be identified in the three-year period from 2003 through 2005. Furthermore, Ecology requires that the worst-case calendar day emissions for each individual unit be modeled (regardless if these happen to occur on different days for different emission units). The only potential exclusions are if it is physically impossible for those units to operate in that fashion or if the units are permitted such that they cannot operate in such a way. Because the focus of the BART program is on normal operations, startups, shutdowns, malfunctions, and upsets can be excluded from the determination of the maximum calendar day emissions. Although the guidance is not explicit in this regard, the modeling analysis in this report is based on the maximum calendar day NOx, $SO_2$, and $PM_{10}$ emissions for a given BART unit, even though these maxima may take place on different days. This, and the assumption that all units

are operating at their worst case emission rate at the same time result in very conservative emission scenarios for the dispersion modeling.

If the control effectiveness values of two control technologies are similar, visibility modeling can be used to select BART.

# 3.0 BART DETERMINATION ANALYSIS – HEATERS & BOILERS

This section addresses BART for the heaters and boilers that are BART eligible. The Cherry Point refinery maintains 15 heaters and two boilers that are subject to BART. All BART heaters and boilers are permitted to combust refinery fuel gas and natural gas. BP is planning to decommission the two BART boilers (i.e., Boilers No. 1 and No. 3) as part of the Boiler Replacement Project in 2008. Consequently, controls for Boiler No. 1 and No. 3 are not addressed in this analysis.

The following sections discuss the BART determination analysis performed for NOx, SO2, and PM10/PM2.5 for the 15 refinery heaters.

## 3.1 NITROGEN OXIDES (NOX)

There are a variety of options available for controlling NOx emissions from combustion sources. Some options involve combustion controls that reduce NOx formation, while others utilize add-on control devices to remove NOx after it is formed. Combinations of combustion controls and add-on controls can also be used to reduce NOx emissions.

Combustion controls reduce NOx emissions by controlling the combustion temperature, flame pattern, and the availability of oxygen. Combustion air containing both nitrogen and oxygen can combine in a high temperature environment to form thermal NOx. The oxidation of nitrogen that is chemically bound in fuel sources can also form NOx (fuel-bound NOx). Refinery fuel gas and natural gas normally do not contain significant amounts of fuel-bound nitrogen; therefore, reduction of thermal NOx formation will be the focus basis of the analyses of the combustion controls for the heaters.

### 3.1.1 Step 1: All Available Retrofit NOx Emission Control Techniques

A review of the current NOx control technologies was conducted and those technologies that were determined to be commercially available for a retrofit on existing refinery heaters are listed in Table 3-1. Table 3-1 also provides a brief description of each technology.

**<u>Selective Catalytic Reduction (SCR)</u>**

Selective Catalytic Reduction (SCR) is a post-combustion control device in which ammonia is injected as the flue gas passes through a catalyst bed. NOx reacts with the ammonia aided by the catalyst to form nitrogen and water. SCR is technically feasible for all refinery heaters and boilers.

**Low NOx Burners/Ultra Low NOx Burners**

Conventional burners can be retrofitted to reduce their NOx emissions with either low NOx burners (LNBs) or ultra low NOx burners (ULNBs). As the name implies, ultra low NOx burners have lower emissions of the two types of burners. However, each has specific retrofit requirements and is not necessarily suited for all applications. Key feasibility criteria include the burner's performance with fuel gas gravity swings for units with high turndown and whether the boiler or heater can accommodate the longer flame pattern that is characteristic of LNBs. BP requested an evaluation of each BART heater from two burner vendors to determine which type would be most appropriate for each heater. This BART determination analysis is based on the type of burner recommended by the vendor, whether low NOx or ultra low NOx, with the associated emission factor. For the purposes of this document, replacing the heater burner with a lower-emitting burner is generally referred to as a LNB replacement regardless of the specific type of burner recommended.

**Selective Non-Catalytic Reduction (SNCR)**

Selective Non-Catalytic Reduction (SNCR) consists of injecting ammonia or urea into combustion unit flue gases in a specific temperature zone of between approximately 1600ºF and 2000ºF. The process relies on good mixing at high temperature to reduce NOx to nitrogen (N2) as the flue gas moves through the ductwork.

For efficient NOx removal using SNCR, the exhaust gas must remain within this temperature range for the appropriate length of time. The ammonia injector must be carefully located to ensure that the exhaust gas temperature is within the acceptable range. Due to the variability in the hydrogen content and heat content of the Cherry Point refinery fuel gas, the exhaust temperature can vary significantly due to normal changes in refinery operation. These variations make SNCR a poor candidate to control NOx on the refinery heaters and boilers. Hence, SNCR is considered technically infeasible overall for the refinery heaters.

**External Flue Gas Recirculation (FGR)**

In external flue gas recirculation (FGR), flue gas is recirculated using a fan and external ducting and is mixed with the combustion air stream thereby reducing the flame temperature and decreasing NOx formation. Generally, when a unit is retrofitted with external FGR, it will require an additional or larger forced draft (FD) fan. Application of external FGR is normally

limited to boilers because there is a risk of recirculating hydrocarbons into the process heater firebox potentially causing an unsafe situation. Therefore, external FGR is considered technically infeasible overall for use on refinery process heaters.

**Low Excess Air Operation – CO Control**

Minimizing the amount of excess air (i.e., oxygen) during the initial stages of combustion decreases the amount of NOx formed. However, reducing the amount of oxygen can cause incomplete combustion, which increases carbon monoxide (CO) emissions. The combustion unit can be operated based on the CO concentration moderating the excess air and therefore, controlling the amount of NOx generated. This CO level would be monitored by an in-situ CO analyzer in the flue gas stream. This technique requires a high level of instrumentation and automation required for burner control (e.g., actuators for draft & air control).

However, low oxygen operation results in longer flames that could cause flame impingement. Also, it is difficult to maintain safe operating conditions at low oxygen levels. Due to the limited viable operating range and potential safety issues, this technique is considered technically infeasible overall for use on refinery heaters.

**Steam Injection**

Steam injection decreases NOx formation by reducing the flame temperature. Steam is delivered either by injecting it directly into the root of the flame or by feeding it with the gaseous fuel. Steam injection can impact combustion unit operation by worsening flame pattern, reducing unit efficiency, and affecting unit stability. Furthermore, the modest NOx reductions at the heater may be offset by NOx emissions resulting from steam generation elsewhere. Also, minimal NOx reductions will be gained in units already fitted with low NOx burners. These issues make steam injection technically infeasible or not appropriate for all but one of the BART refinery heaters. The specific technical reasons that steam injection is inappropriate are listed in Table 3-2 for each heater.

The only heater where steam injection is potentially feasible is the 1$^{st}$ Stage HC Fractionator Reboiler. However, BP proposes that installation of a ULNB is BART for this heater because it will provide a greater degree of NOx reduction than steam injection.

**Lower Combustion Air Preheat**

Reducing the combustion air temperature decreases NOx formation by reducing flame temperature. This technique is only applicable to units equipped with air preheat. For units that are not equipped with air preheat, combustion air is already entering at ambient air temperature and lowering the combustion air temperature is not practical. Also, if the heater is already at maximum capacity, there is no extra capacity to accommodate a lower combustion air temperature; lowering the combustion air temperature would reduce heater capacity, which eliminates this control from BART consideration for that unit. Finally, if cooler air is introduced into the heater as combustion air, the heater has to utilize additional fuel to heat the air for the combustion process which ends up negating any NOx reductions generated. These issues make reducing the combustion air temperature technically infeasible for the BART refinery heaters. The specific technical rationale that lowering combustion air temperature is inappropriate is identified in Table 3-3 for each heater.

**CETEK - Descale & Coat Tubes**

Removing the scale and applying a coating to the heat transfer surfaces can reduce the firebox temperature and decrease NOx formation by improving heat transfer. This technique applies in units where the heat transfer tubes are externally scaled. Conversely, the layer of scaling acts as insulation protecting the tubes from damage. Removing the scale to reduce emissions will also reduce firing rate.

This method of NOx reduction does not apply to most of the refinery heaters. The #1 Reformer Heaters are the only BART units that exhibit scaling. The flames in the burners in the #1 Reformer Heaters currently impinge somewhat on the tubes and the scale protects the tubes from being damaged by the flames. As such, this emission control method cannot be implemented until the flame impingement issue is addressed in the #1 Reformer Heaters. Therefore, descaling and coating the tubes is eliminated from consideration in this BART analysis.

**Firebox Sealing**

Firebox sealing has the potential to reduce NOx emissions and, thus, is included as a potential NOx control option. However, this technique is a standard maintenance procedure for BP and is already incorporated in baseline data.

**Fuel Biasing & Overfire Air**

The fuel biasing and overfire air methods to reduce NOx emissions only apply to units with multi-level burners. Because none of the BART heaters at Cherry Point has multi-level burners, neither of these technologies is applicable.

**Modify Existing Burners to Improve NOx**

Although it is possible to modify burner tips to change fuel distribution among different burner zones, each burner in each boiler and heater at the refinery has been engineered for optimum performance, reliability, and safety. Consequently, it is important to understand all the ramifications prior to attempting to redesign burners to achieve lower NOx. For example, one could modify the burners to achieve a longer flame that might result in cooler combustion temperatures and reduced NOx formation. However, the longer flame can result in flame impingement which may damage the heater. Consequently, BP finds that modifying existing burners is technically infeasible for all but one of the BART refinery heaters. The specific technical reasons that modifying burner tips is inappropriate are listed in Table 3-4 for each heater.

The only heater where modifying the existing conventional burners is potentially feasible is the 1st Stage HC Fractionator Reboiler. However, BP proposes to install ULNB as BART for this heater; ULNB will provide a greater NOx reduction than expected by modifying the burner tips.

**Low Excess Air Operation – Improved Combustion Air Control**

As stated above, minimizing the amount of excess air (i.e., oxygen) during the initial stages of combustion decreases the amount of NOx formed. This technique requires that the unit operate continuously at design excess oxygen levels using automated control for draft and air. It only applies to units currently operating with high excess oxygen and is not practical for low duty and low firebox temperature applications. This procedure is not applicable at the Cherry Point Refinery because all heaters are already operating at minimal excess air.

### 3.1.2 Step 2: Eliminate Technically Infeasible NOx Control Options

In Step 1, each of the potential NOx control technologies was evaluated to determine if it is technically feasible for the BART heaters at Cherry Point. Feasibility was discussed as each control option was introduced; Table 3-5 summarizes the outcome of this determination.

After those controls that are deemed technically infeasible and not applicable are removed, the only control technologies applicable to the BART refinery heaters are SCR and LNB. The potential as a BART control of each of these are reviewed on a unit-by-unit basis and discussed in the following sections.

### 3.1.3 Step 3: Evaluate Control Effectiveness of Remaining NOx Control Technologies

Based on this analysis, the most effective remaining technologies for the heaters in decreasing order of effectiveness are:

- LNB plus SCR (vendor guarantee control + the less effective of 95% or 5ppm)
- SCR (95% or 5ppm, whichever is higher emissions)
- LNB (vendor guarantee)

The control effectiveness of LNB technology was based on the higher predicted NOx guarantee of the two vendor guarantees obtained for each specific heater with some adjustment based on refinery process knowledge. Based on discussions with vendors, the most stringent control effectiveness that can be expected for SCR is 95% control or 5 ppm NOx, whichever results in higher emissions. This control effectiveness was selected because vendors are generally unable to guarantee NOx concentrations below 5 ppm. Placing a LNB in front of a SCR will reduce the amount of NOx entering the SCR; however, the overall emission rate will still be based on the control efficiency of the SCR – 95% or 5 ppm, whichever results in higher emissions.

### 3.1.4 Step 4: Evaluate Impacts and Document the Results

Five aspects were included in this analysis: costs of compliance, energy impacts, non-air quality environmental impacts, collateral emissions impacts, and remaining useful life. Only those technologies deemed to be technically feasible were evaluated in this step.

Ecology recommends that the cost effectiveness methodology be consistent with EPA's OAQPS Control Cost Manual. Additionally, in accordance with Ecology guidance, the BART cost analyses are expressed in 2006 dollars with a 7% Capital Recovery Annual Interest Rate.

**Cost of Compliance**

BP performed this analysis with a two-phase approach. The first phase (called APPRAISE) evaluated all the technically feasible technologies for all units based on conceptual, budgetary level cost estimates (rough order of magnitude [ROM] ± 50%).

The APPRAISE cost estimates were reviewed considering both the cost values and the likelihood of success to determine which technologies were BART possibilities. Those with preliminary cost effectiveness values over $20,000/ton were eliminated from further BART analysis; this cost threshold is more than twice what is typically considered cost effective in Washington BACT analyses. Those with cost effectiveness values less than $10,000/ton were identified for further cost analysis.

Those controls designated for additional analysis were further examined in the second phase (called SELECT). Once the SELECT analysis was complete, the APPRAISE phase estimates were updated using the more accurate system costs obtained during SELECT.

Once the SELECT cost analyses were completed, it was generally assumed that technologies with cost effectiveness values greater than $15,000/ton and those with incremental cost effectiveness values greater than $30,000/ton were eliminated as BART. Once again, these cost criteria are substantially above those typically applied in Washington BACT analyses.

**APPRAISE Phase**

In the first phase, capital costs for control options were developed primarily by scaling historical costs from projects executed by Jacobs Engineering (Jacobs) and/or by applying Lang Factors (published cost estimation factors) and field condition factors to preliminary estimated costs for major equipment. Note that the equipment was designed and sized to maintain current operating throughput. This accounts for such items as foundations, piping, electrical, instrumentation, labor, engineering, accessories & auxiliaries, etc. As needed, the capital costs were updated to 2006 dollars using the Nelson-Farrar Cost Indexes for Refinery Construction.

Equipment budget pricing was obtained from vendors or using common unit pricing values. Preliminary equipment sizes were based on initial process performance calculations. Scaling using the six tenths method was also used to extrapolate equipment budget pricing from known equipment pricing of differing size as follows:

$$C_2 = C_1 \times \left( \frac{Q_2}{Q_1} \right)^{0.6}$$

where:

| | | |
|---|---|---|
| $C_1$ | = | Known Cost for Equipment |
| $C_2$ | = | Estimated Cost for New Equipment |
| $Q_1$ | = | Capacity for Known Cost Equipment |
| $Q_2$ | = | Capacity for New Equipment |

The BART cost analysis is also to address costs related to retrofitting the existing units. As part of that, for the first phase, Jacobs applied a 40% contingency factor that is typically used for budgetary level cost estimates. This contingency is to address details not explicitly included in the initial capital cost estimate, such as generic instrumentation, sales tax, freight, construction and field expenses, and contractor fees. Also, the installed cost for the SCR was multiplied by a retrofit factor of 1, 1.1, or 1.3, depending upon the complexity of installing a SCR into the existing available space.

The cost analysis also addressed: cost of catalyst; run life of catalyst and turn around cycles; installation and operation of continuous emission monitoring systems (CEMS); maintenance costs related to installation of additional fans; handling and storage of chemicals such as ammonia; installation of Safety Instrumented Systems (SIS); and electrical infrastructure expansion when necessary. Also included were cost estimates related to loss of production due to the installation of the control technology prolonging the regularly-scheduled maintenance turnarounds.

Annualized operating costs included maintenance costs, utilities costs, and chemical costs. As per the OAQPS manual, the maintenance costs were assumed to be 1.5% of the total capital investment.[5] In the APPRAISE phase calculations, it was conservatively assumed that the control equipment would not require any additional labor or supervisory labor or other operating costs.

[5] OAQPS Control Cost Manual, Fifth Edition, February 1996, EPA 453/B-96-001, Section 4.2, Chapter 2, page 2-45

Incremental cost effectiveness values were calculated as discussed above examining the control and the next most stringent control. For NOx emissions from the heaters, this means calculating the incremental cost from LNB to SCR, and then from SCR to LNB+SCR. In the cases where LNBs were not feasible or are already installed, incremental costs were not calculated.

The control device and heater pairings with average and incremental cost effectiveness values that required a SELECT level analysis are:

- SCR for the Crude Charge Heater
- SCR for the #1 Reformer Heaters
- ULNB for the Steam Reforming Furnace #1 – (North H2 Plant)
- SCR for the Steam Reforming Furnace #1 – (North H2 Plant)
- ULNB for the Steam Reforming Furnace #2 – (South H2 Plant)
- SCR for the Steam Reforming Furnace #2 – (South H2 Plant)
- ULNB for the 1st Stage HC Fractionator Reboiler

**SELECT Phase**

The second phase, or SELECT phase, creates a cost analysis using more project-specific information. Using process flow diagrams (PFDs), piping and instrumentation diagrams (P&IDs), similar equipment review, and process knowledge, Jacobs estimated the equipment, demolition, site work, pilings, buildings, concrete, structural steel, ducting, piping, insulation, instrumentation, electrical, painting, scaffolding, and fire protection requirements for each unit and control option. Using these estimates, both installation and operating costs for each unit/control pairing were generated.

Note that the equipment was designed and sized to maintain current operating throughput. The generic design assumptions and design basis for the SCR and the ammonia skid are outlined in figures in Appendix B.

Burner vendors were requested to identify the lowest NOx burners capable of performing at any load (maximum heater release, normal operation, and minimum turndown conditions) at or below the following emission limits:

- For heaters without air preheat, 0.035 lb NOx/MMBtu (HHV, dry, 3% excess O2) fired. For heaters featuring air preheat, 0.040 lb NOx/MMBtu.

- CO emissions not to exceed 400 ppmvd with the same firing conditions.

BP also requested that burner vendors assess the performance risk associated with the application of the lowest NOx burners, using criteria ranging from "No concern" to "Not recommended." If burners were not recommended, the vendor was asked to justify that statement. Finally, the vendors were asked to identify any other feasible means for incremental NOx reduction (FGR, overfire air, etc.).

Material pricing was based on the most recent available data in Jacobs' in-house databases. In addition, labor required for the installation and its productivity are estimated. Labor estimates were based on Jacobs' standards and actual costs for similar work. Budget quotes from vendors were obtained for the major equipment for each specific project, including burner items, SCR equipment, testing costs, and electrical equipment.

The SELECT phase cost estimate also addresses:

- Freight costs: Assumed to be six percent of material cost. Freight from Europe for the air preheaters associated with the SCR installation is included in the equipment cost.

- Design allowance: A contingency included in each category of expense (e.g., equipment, demolition, site work, etc.) to cover costs that are known to occur, but for which no information was available at this stage of design. Design allowances vary between 10 and 20 percent of the cost in that category and are based on historical information.

- Sales tax: Sales tax was excluded from the analysis for all but rental costs.

- Productivity: When the labor costs were estimated, the efficiency, or productivity, of each discipline/trade was included to create realistic estimates of actual labor hours from which costs were calculated.

- Construction: Labor rates are based on direct hire construction as provided by BP. These rates include base salary, fringe benefits, payroll taxes & insurance, small tools, and overhead.

- Escalation: The project estimate was de-escalated to 2006 dollars according to Ecology's guidance. Escalation, however, is a major consideration in forecasting the actual future cost of the installations.

- Field Indirects: Included in the all-in wage rate; incorporates construction services labor, temporary field services, non-payroll taxes & insurance, small tools, consumables & construction equipment, and field staff.

- Professional Services: Includes front-end scoping services, detailed engineering & design, procurement, construction support, project representation, and as-builts/closeouts.

- Client Costs: 8 percent.

- Contingency: The cost estimate for each unit and control pairing was reviewed using a Monte Carlo risk assessment model to determine the reliability of the components of the cost estimate and, based on this review, assign a project-specific contingency factor. The contingency factors ranged from approximately 17 to 20 percent of the total installed construction cost including equipment, materials, engineering, and construction. This contingency is part of the estimated job cost and is to cover items which have been inadvertently left out of the estimate, minor delays in deliveries of equipment or materials, etc. It does not cover the cost of additional work or scope changes after the definition of the job has been frozen for the estimate.

- Commercial Loss: Installations for individual BART compliance projects will be associated with currently scheduled cycle ending turnarounds (TAR) for the various operating units affected, which range from the years 2011 to 2015. Each TAR has a specific number of planned days for the work required for scheduled capital and maintenance for that unit. Potential LNB or SCR additions to heaters were evaluated against the already planned number of days by the refinery TAR Planning group. If the additional scope added days to the TAR, lost revenue for those days was calculated and incorporated into the cost calculation. If no additional days were needed, there was no impact to the TAR, no lost revenue and no impact to the cost calculation.[6]

As part of SELECT, the estimates were also refined for the installation of the SIS and the CEMS. SIS is an upgrade to the control system for combustion units that is required by the Process Safety Management System overseen by OSHA. It was assumed that installation of both the SIS, if not already installed, and a CEMS would be included with any selected BART control technology. However, when examining combined technologies (e.g., LNB plus SCR), the SIS and CEMS costs were only included once.

As discussed in the following sections, energy impacts, non-air quality environmental impacts, collateral emissions impacts, and remaining useful life were included in the cost analysis as appropriate.

[6] No BART modifications were eliminated due to lost revenue resulting from extended TAR periods.

**Energy Impacts**

Energy impacts were evaluated for each technically feasible control technology. Evaluations of energy use were based on discussions with BP and Jacobs specialists. Costs of energy were provided by the BP Energy Specialist based on Cherry Point Refinery norms as used for other projects.

Several energy penalties were addressed in the operating costs, including electricity consumption for additional use of or larger support equipment (e.g., fans), and electricity use of the control technologies (e.g., SCR). In this analysis, equipment sizing was based on maintaining current operating throughput.

**Non-air Quality Environmental Impacts**

Non-air quality environmental impacts were reviewed in regards to the potential BART control technologies. Any costs incurred from the handling and treatment of by-products and wastes were included in the cost analysis.

The spent SCR catalyst is the only waste stream identified in the cost analysis for NOx control on refinery heaters. The cost analysis assumes that the SCR catalyst has a five year life. Spent catalyst will require disposal or recycling.

Also, storing ammonia on-site for use in a SCR may require an update to the Risk Management Plan (RMP).

**Collateral Emissions**

For fired units, implementation of certain NOx control technologies would introduce new emissions (e.g., ammonia from SCRs) or cause an increase in existing emissions (e.g., CO from low NOx burners).

Low NOx burners (LNB), as well as conventional burners, are capable of low CO emissions when fired at normal to maximum design capacities. Typically, this is the point at which the vendor will guarantee the CO levels. However, as the burner is turned down, LNB will usually produce higher CO levels than a conventional burner. As such, any permit limits resulting from the BART program should be set to accommodate these variations in emissions due to changes in operation.

The SCR technology removes NOx from the exhaust stream by injecting ammonia into the flue gas as it passes through a catalyst bed. A balance must be struck: enough ammonia must be injected to react with as much NOx as possible; but, any unreacted ammonia will escape with the flue gas and cause ammonia emissions. The ammonia that escapes is called "ammonia slip." The SCRs in this analysis are being designed to a 5 ppmvd ammonia slip at 3% oxygen during normal operation. In addition, sulfur in fuel gas can combine with the ammonia injected into the SCR to produce ammonium bisulfate emissions.

**Remaining Useful Life**

The remaining useful life is taken into account in determining the annualized cost when evaluating the control options. As the remaining useful life gets shorter, the annualized cost increases. In this analysis, the remaining useful life for all BART-eligible sources and control devices was assumed to be the same as for new equipment, 20 years. This assumption means that there is no discounting of the cost to account for a shorter life-span. The catalyst life for SCR is assumed to be five years.

The controlled emission factors, controlled emission rates, cost effectiveness and incremental cost effectiveness values for each unit and control device are summarized in Table 3-6. Further detail and supporting calculations are discussed in the following sections.

#### *3.1.4.1 Crude Charge Heater*

The Crude Charge Heater is currently fitted with conventional burners.

*Low NOx Burners*: Installing LNBs on the Crude Charge Heater is not technically feasible. There is a serious technical risk due to the high heat density. It would also require reducing heater capacity and unit throughput.

*Selective Catalytic Reduction*: The BART cost effectiveness analysis to install a SCR on the Crude Charge Heater is included in Table C-1 in Appendix C. With a cost effectiveness of $32,001/ton, this control option is eliminated as BART.

*Low NOx Burners + Selective Catalytic Reduction*: Because a LNB installation is technically infeasible, the combination of LNB and SCR is also technically infeasible.

BP proposes that good operational practices are BART for NOx for the Crude Charge Heater.

#### *3.1.4.2 South Vacuum Heater*

The South Vacuum Heater was fitted with Ultra Low NOx Burners (Northwest Clean Air Agency [NWCAA] Order of Approval to Construct [OAC] #902, February 7, 2005, revised November 1, 2005).

*Low NOx Burners*: ULNBs have already been installed on the South Vacuum Heater. Further NOx reduction is not possible using burner upgrades due to high air preheat. Because the ULNBs were permitted and installed in 2005, their associated emissions reductions are incorporated as part of the baseline and not included as a BART reduction.

*Selective Catalytic Reduction*: The BART cost effectiveness analysis to install a SCR on the South Vacuum Heater with existing ULNB is included in Table C-2 in Appendix C. With a cost effectiveness of $82,643/ton, this control option is eliminated as BART.

BP proposes that the existing ULNBs are BART for NOx for the South Vacuum Heater.

#### *3.1.4.3 Naphtha HDS Charge Heater & Naphtha HDS Stripper Reboiler*

The Naphtha HDS Charge Heater and the Naphtha HDS Stripper Reboiler are currently fitted with conventional burners.

*Low NOx Burners*: Installing ULNBs on the Naphtha HDS Charge Heater and the Naphtha HDS Stripper Reboiler would require a significant derate of both units to avoid safety concerns related to flame impingement and this option was not pursued. Because BART guidelines do not require consideration of control options that de-rate a unit, this option is eliminated from further consideration.

*Selective Catalytic Reduction*: The BART cost effectiveness analysis to install SCRs on the Naphtha HDS Charge Heater or the Naphtha HDS Stripper Reboiler is included in Tables C-3 and C-4 in Appendix C. With a cost effectiveness of $32,175/ton for the Naphtha HDS Charge Heater and $40,711/ton for the Naphtha HDS Stripper Reboiler, this control option is eliminated as BART for both of these heaters.

*Low NOx Burners + Selective Catalytic Reduction*: Because a ULNB installation is technically infeasible, the combination of ULNB and SCR is also technically infeasible.

BP proposes that good operational practices are BART for NOx for both the Naphtha HDS Charge Heater and the Naphtha HDS Stripper Reboiler.

#### *3.1.4.4 #1 Reformer Heater*

The #1 Reformer Heater has a complex design with four independent fire boxes and two stacks. It is currently fitted with conventional burners.

*Low NOx Burners*: Installing LNBs on the #1 Reformer Heaters is not technically feasible. The existing burners produce the shortest, most compact flame available yet flame impingement on the tubes is a serious problem. Any LNB currently available will produce a longer flame which would be more susceptible to heater currents and would be expected to result in much greater levels of flame impingement. As such, LNB are considered technically infeasible and eliminated from consideration as BART.

*Selective Catalytic Reduction*: The SCR cost effectiveness analysis included in Table C-5 in Appendix C. With a cost effectiveness of $17,299/ton, this control option is eliminated as BART.

*Low NOx Burners + Selective Catalytic Reduction*: Because a LNB installation is technically infeasible, the combination of LNB and SCR is also technically infeasible.

BP proposes that good operational practices are BART for NOx for the #1 Reformer Heaters.

#### *3.1.4.5 Coker Charge Heater (#1 North) & Coker Charge Heater (#2 South)*

The Coker Charge Heater (#1 North) and Coker Charge Heater (#2 South) are currently fitted with early technology LNB with staged air combustion and flue gas recirculation permitted in 1999. The operation of coker heaters is unique due to the cyclic nature of the unit and alternate fuel source which limits the effectiveness of NOx control technologies.

*Low NOx Burners*: The BART cost effectiveness analysis is included in Tables C-6 and C-7 in Appendix C. With a cost effectiveness of $31,301/ton for the north heater and $30,762/ton for the south heater, this control option is eliminated as BART for both of these heaters.

*Selective Catalytic Reduction*: The BART cost effectiveness analysis is included in Tables C-8 and C-9. The incremental cost effectiveness values are summarized in Table 3-6. The cost effectiveness value is $35,202/ton for the north heater and $34,597/ton for the south heater; the incremental cost to go from LNB to SCR as the next most stringent control device is $38,832/ton for the north heater and $38,164/ton for the south heater. Considering these cost effectiveness values, this control option is eliminated as BART for both of these heaters.

*Low NOx Burners + Selective Catalytic Reduction*: The cost effectiveness calculation assumes that the LNB installation and cost will not change as a result of the SCR installation. The SCR costs were adjusted (downward) to account for the lower post-LNB inlet NOx concentration resulting in needing less catalyst and less ammonia consumption. The average cost calculations for the Coker Charge Heaters are included in Tables C-10 and C-11 in Appendix C.

The incremental cost effectiveness values are summarized in Table 3-6. The SCR controls NOx emissions to either 95% or 5 ppm, whichever results in higher emissions. Based on this parameter, installing SCR by itself will control to 5 ppm and installing it in concert with a ULNB also will control to 5 ppm. As such, there is no emissions change between SCR and LNB+SCR and the incremental cost effectiveness does not exist.

With a cost effectiveness of $43,460/ton for the north heater and $42,738/ton for the south heater, this combined control option is eliminated as BART for both of these heaters.

BP proposes that the existing LNB with staged air combustion coupled with good operational practices is BART for NOx for both the Coker Charge Heater (#1 North) and Coker Charge Heater (#2 South).

#### *3.1.4.6 Diesel HDS Charge Heater & Diesel HDS Stabilizer Reboiler*

The Diesel HDS Charge Heater and Diesel HDS Stabilizer Reboiler were fitted with Ultra Low NOx Burners (NWCAA OAC #949, March 31, 2006).

*Low NOx Burners*: ULNBs have already been installed on the Diesel HDS Charge Heater and Diesel HDS Stabilizer Reboiler. Because the ULNBs were permitted and installed in 2006, after the baseline period of 2003 to 2005, their associated emissions reductions are not considered part of the baseline and, therefore, are included as a BART reduction.

*Selective Catalytic Reduction*: The BART cost effectiveness analysis to install SCRs on the Diesel HDS Charge Heater and Diesel HDS Stabilizer Reboiler is included in Tables C-12 and C-13 in Appendix C. With a cost effectiveness of $282,388/ton for the Diesel HDS Charge Heater and $206,592/ton for the Diesel HDS Stabilizer Reboiler, this control option is eliminated as BART for both of these heaters.

BP proposes that the existing ULNBs are BART for NOx for both the Diesel HDS Charge Heater and Diesel HDS Stabilizer Reboiler.

#### *3.1.4.7 Steam Reforming Furnace #1 - (North H2 Plant) & Steam Reforming Furnace #2 - (South H2 Plant)*

The Steam Reforming Furnace #1 (North H2 Plant) and the Steam Reforming Furnace #2 (South H2 Plant) are fitted with conventional burners.

*Low NOx Burners*: The BART cost effectiveness analysis to install ULNB on the Steam Reforming Furnace #1 – (North H2 Plant) and Steam Reforming Furnace #2 – (South H2 Plant) is included in Tables C-14 and C-15 in Appendix C. With a cost effectiveness value of $31,430/ton for the north furnace and $32,045/ton for the south furnace, this control option is eliminated as BART for both of these heaters.

*Selective Catalytic Reduction*: The BART cost effectiveness analysis to install SCR on the Steam Reforming Furnaces is included in Table C-16 and C-17 in Appendix C. The incremental cost effectiveness values are summarized in Table 3-6. The cost effectiveness value is $46,449/ton for the north furnace and $47,320/ton for the south furnace; the incremental cost to go from LNB to SCR as the next most stringent control device is $59,622/ton for the north furnace and $60,719/ton for the south furnace. Considering these cost effectiveness values, this control option is eliminated as BART for both of these heaters.

*Low NOx Burners + Selective Catalytic Reduction*: The cost effectiveness calculation assumes that the LNB installation and cost will not change as a result of the SCR installation. The SCR costs were adjusted (downward) to account for the lower post-LNB inlet NOx concentration resulting in needing less catalyst and less ammonia consumption. The average cost calculation for the Steam Reforming Furnaces is included in Tables C-18 and C-19 in Appendix C.

The incremental cost effectiveness values are summarized in Table 3-6. The SCR controls NOx emissions to either 95% or 5 ppm, whichever results in higher emissions. Based on this parameter, installing SCR by itself would control to 5 ppm and installing it in concert with a ULNB also would control to 5 ppm. As such, there is no emissions change between SCR and LNB+SCR and the incremental cost effectiveness does not exist.

With a cost effectiveness of $55,197/ton for the north furnace and $56,242/ton for the south furnace, this combined control option is eliminated as BART for these furnaces.

BP proposes that good operating practices are BART for NOx for both the Steam Reforming Furnace #1 (North H2 Plant) and the Steam Reforming Furnace #2 (South H2 Plant).

#### *3.1.4.8 R-1 HC Reactor Heater*

The R-1 HC Reactor Heater was fitted with Ultra Low NOx Burners (NWCAA OAC #966, August 9, 2006).

*Low NOx Burners*: ULNBs have already been installed on the R-1 HC Reactor Heater. Because the ULNBs were permitted and installed in 2006, after the baseline period of 2003 to 2005, their associated emissions reductions are not considered part of the baseline and, therefore, are included as a BART reduction.

*Selective Catalytic Reduction*: The BART cost effectiveness analysis to install SCRs on the R-1 HC Reactor Heater is included in Table C-20 in Appendix C. With a cost effectiveness of $214,726/ton, this control option is eliminated as BART for this heater.

BP proposes that the existing ULNB is BART for NOx for the R-1 HC Reactor Heater.

#### *3.1.4.9 R-4 HC Reactor Heater*

The R-4 HC Reactor Heater is fitted with conventional burners.

*Low NOx Burners Only*: Installing ULNBs on the R-4 HC Reactor Heater is not technically feasible. A serious risk exists due to the high heat density, flame impingement, flame shape, and an exceedance of the API guidelines for burner spacing.

*Selective Catalytic Reduction Only*: The BART cost effectiveness analysis to install SCR on the R-4 HC Reactor Heater is included in Table C-21 in Appendix C. With a cost effectiveness of $36,620/ton, this control option is eliminated as BART for this heater.

*Low NOx Burners + Selective Catalytic Reduction*: Because a LNB installation is technically infeasible, the combination of LNB and SCR is also technically infeasible.

BP proposes that good operational practices are BART for NOx for the R-4 HC Reactor Heater.

#### *3.1.4.10 1st Stage HC Fractionator Reboiler*

The 1$^{st}$ Stage HC Fractionator Reboiler is fitted with conventional burners.

*Low NOx Burners Only*: The BART cost effectiveness analysis to install ULNB on the 1$^{st}$ Stage HC Fractionator Reboiler is included in Table C-22 in Appendix C. With a cost effectiveness value of $12,044/ton, this control option is not cost-effective as BART for this

heater. Nonetheless, BP proposes to install ULNB on this unit to achieve 0.05 lb NOx/MMBtu.[7]

*Selective Catalytic Reduction Only*: The BART cost effectiveness analysis to install SCR on the 1st Stage HC Fractionator Reboiler is included in Table C-23 in Appendix C. The incremental cost effectiveness values are summarized in Table 3-6. The cost effectiveness value is $19,470/ton; the incremental cost to go from LNB to SCR as the next most stringent control device is $36,945/ton. Considering these cost effectiveness values, this control option is eliminated as BART for this heater.

*Low NOx Burners + Selective Catalytic Reduction*: The cost effectiveness calculation assumes that the LNB installation and cost will not change as a result of the SCR installation. The SCR costs were adjusted (downward) to account for the lower post-LNB inlet NOx concentration resulting in needing less catalyst and less ammonia consumption. The average cost calculation for the 1st Stage HC Fractionator Reboiler is included in Table C-24 in Appendix C. The incremental cost effectiveness values are summarized in Table 3-6.

The cost effectiveness value is $23,518/ton; the incremental cost to go from LNB to SCR as the next most stringent control device is $402,903/ton. Considering these cost effectiveness values, this combined control option is eliminated as BART for this heater.

BP proposes that ULNB is BART for NOx for the 1st Stage HC Fractionator Reboiler.

#### *3.1.4.11 2nd Stage HC Fractionator Reboiler*

The 2nd Stage HC Fractionator Reboiler was fitted with Low NOx Burners (NWCAA OAC #847, November 13, 2003).

*Low NOx Burners*: The BART cost effectiveness analysis to replace the existing LNB with ULNB on the 2nd Stage HC Fractionator Reboiler is included in Table C-25 in Appendix C. With a cost effectiveness of $36,395/ton, this control option is eliminated as BART for this heater.

[7] This unit has combustion air preheat. Although burner vendors indicated they could achieve 0.04 lb NOx/MMBtu, BP's operating experience indicates this is an extremely aggressive limit. Because BP lacks confidence that 0.04 lb/MMBtu can be achieved on a continuous basis, BP proposes 0.05 lb/MMBtu.

*Selective Catalytic Reduction*: The BART cost effectiveness analysis to install SCRs on the 2nd Stage HC Fractionator Reboiler is included in Table C-26 in Appendix C. With a cost effectiveness of $37,810/ton, this control option is eliminated as BART for this heater.

*Low NOx Burners + Selective Catalytic Reduction*: The cost effectiveness calculation assumes that the LNB installation and cost will not change as a result of the SCR installation. The SCR costs were adjusted (downward) to account for the lower post-LNB inlet NOx concentration resulting in needing less catalyst and less ammonia consumption. The average cost calculation for the 2nd Stage HC Fractionator Reboiler is included in Table C-27 in Appendix C.

The incremental cost effectiveness values are summarized in Table 3-6. The SCR controls NOx emissions to either 95% or 5 ppm, whichever results in higher emissions. Based on this parameter, installing SCR by itself will control to 5 ppm and installing it in concert with a ULNB also will control to 5 ppm. As such, there is no emissions change between SCR and LNB+SCR and the incremental cost effectiveness does not exist.

With a cost effectiveness of $40,768/ton, this combined control option is eliminated as BART for this heater.

BP proposes that the existing low NOx burners are BART for NOx for the 2nd Stage HC Fractionator Reboiler.

Table 3-7 summarizes the proposed BART for NOx emissions from BART-eligible heaters at Cherry Point Refinery.

## 3.2 SULFUR DIOXIDE (SO2)

SO2 emissions from combustion sources result from the oxidation of sulfur in the fuel. There are generally two methods of reducing SO2 emissions from fired sources – pollution prevention by removing the sulfur in the fuel prior to combustion or add-on technologies that remove the SO2 from the flue gas stream prior to release.

### 3.2.1 Step 1: All Available Retrofit SO2 Emission Control Techniques

A review of the current SO2 control technologies was conducted and those technologies that were determined to be commercially available for a retrofit on existing refinery heaters are listed and described in Table 3-8. Technologies include:

- Emerachem EMX
- Dry Scrubbing
- Fuel Gas Conditioning
- Spray Tower Scrubbing

### 3.2.2 Step 2: Eliminate Technically Infeasible Options

Each of the potential SO2 control technologies listed in Step 1 was evaluated to determine if they would be technically feasible for the BART heaters at Cherry Point.

**Emerachem EMX**

Emerachem EMX is an add-on technology that utilizes a catalyst to absorb the SO2 in the flue gas. The catalyst is periodically regenerated using hydrogen. The regenerated stream is treated in a sulfur recovery unit or adsorbed on carbon. This technology has not been proven to run longer than one year without a turnaround. As was mentioned previously, BP requires the refinery heaters to be able to operate five years between turnarounds. As such, Emerachem EMX was not longer considered for use on the refinery heaters.

**Dry Scrubbing**

Dry scrubbing is also an add-on technology where the SO2 in the flue gas reacts with injected bicarbonate; the products of the reaction are removed in a baghouse. This technology requires

a turnaround approximately every two years due to equipment plugging and wear. Therefore, this technology was not pursued for application to refinery heaters.

Two options, fuel gas conditioning and spray tower scrubbing, are considered technically feasible.

### 3.2.3 Step 3: Evaluate Control Effectiveness of Remaining SO2 Control Technologies

**Fuel Gas Conditioning**

BP expects fuel gas conditioning to reduce the concentration of sulfur in fuel gas to 50 ppmv. Based on an engineering assessment by Jacobs, this would reduce the average sulfur concentration in fuel gas combusted by BART-eligible heaters by 89%.

**Spray Tower Scrubbing**

For spray tower scrubbing, the most stringent control effectiveness was considered to be 95% control. This control effectiveness was selected because Jacobs has found that vendors are reluctant to guarantee a lower number because of measurement inaccuracies. Utilizing both fuel gas conditioning and spray tower scrubbing is assumed to be essentially additive: the fuel gas conditioning brings the fuel gas sulfur content down to 50 ppmv and then the spray tower scrubbing removes 95% of the remaining SO2. When evaluating the combination of the two technologies, the spray tower scrubbing costs were adjusted (downward) to account for the lower post-fuel gas conditioning inlet SO2 concentration resulting in less caustic consumption and reduced waste disposal requirements.

Based on this analysis, the remaining technologies for the heaters in decreasing order of effectiveness are:

- Fuel gas conditioning + Spray tower scrubbing (50 ppmv fuel gas sulfur content + 95% SO2 control)
- Spray tower scrubbing (95% SO2 control)
- Fuel gas conditioning (50 ppmv fuel gas sulfur content, 89% SO2 control)

### 3.2.4 Step 4: Evaluate Impacts and Document the Results

Five aspects were included in this analysis: costs of compliance, energy impacts, non-air quality environmental impacts, collateral emissions impacts, and remaining useful life. This analysis was performed similarly to that for NOx.

**Cost of Compliance**

BP performed this BART determination analysis for the add-on control devices based on a budgetary level cost (APPRAISE level, ROM ± 50%) addressing both installation and annual operating costs. The operating costs were estimated based on experience with several existing hydrodesulfurization units at BP and general assumptions regarding the operating and maintenance costs for the fuel gas conditioning project. Due to the analysis results, a more refined cost analysis was not required to make the BART determination.

**Energy Impacts**

For the spray tower, an additional ID fan and other equipment would require electricity for operation. The electricity costs, based on estimates provided by the BP Energy Specialist, were included in the BART analysis.

Additional electrical, amine system, and steam needs due to the installation of the fuel gas conditioning project were not explicitly addressed in this budgetary cost estimate. If fuel gas conditioning had been selected as the BART control, refined cost estimates would have been developed as the project advanced.

**Non-air Quality Environmental Impacts**

With spray tower scrubbing, the flue gas is routed through a spray tower where SO2 reacts with caustic. The spent caustic must be handled and disposed of. The cost for waste disposal is included in the BART cost analysis. This analysis assumes that the existing effluent (wastewater treatment) plant will be able to handle the entrained solids and caustic in the waste stream.

The fuel gas conditioning acts to remove sulfur compounds from the fuel gas stream. This sulfur stream would be treated by the Sulfur Recovery Unit (SRU). Jacobs estimates that this additional sulfur removal would result in approximately one ton per day of additional load on the SRU.

**Collateral Emissions**

The spray tower would not be expected to have any collateral emissions of criteria pollutants. However, with the additional water vapor in the exhaust, the plume could become visible which can create a public perception issue.

Fuel gas conditioning has the potential to reduce multiple pollutants (i.e., SO2 and PM10/PM2.5). This analysis assumes that fuel gas conditioning will be installed to control one primary pollutant. As such, the full cost of fuel gas conditioning is utilized in the BART determination analysis for both SO2 and PM10/PM2.5.

Fuel gas conditioning would require additional steam, thereby potentially increasing emissions from the refinery boilers. Also, due to the additional load on the SRU, fuel gas conditioning would be expected to increase emissions from the SRU.

**Remaining Useful Life**

As with the NOx analysis, the remaining useful life of all refinery heaters and control devices was assumed to be 20 years.

#### *3.2.4.1 BART for SO2 for Refinery Heaters*

Both fuel gas conditioning and spray tower scrubbing are considered technically feasible for refinery heaters. The results of the BART cost analyses to install spray tower scrubbing, fuel gas conditioning, and the combination of the two on each of the BART refinery heaters are summarized in Table 3-9. The supporting calculations are included in Tables D-1 to D-31 in Appendix D.

Fuel gas conditioning would reduce $SO_2$ emissions from all heaters, both BART and non-BART, whereas spray tower scrubbing could be applied to each heater individually. The costs for fuel gas conditioning were divided among BART-eligible heaters in proportion to the mass of SO2 emission reduction that occurred for each heater.

With a cost of $22,282/ton for fuel gas conditioning and ranging from $32,733/ton to $168,330/ton for spray tower scrubbing, neither fuel gas conditioning nor spray tower scrubbing is cost-effective. With cost effectiveness ranging from $49,743/ton to $179,151/ton, the combination of the two technologies also falls outside the cost-effective range.

Table 3-9 indicates the incremental cost of installing a spray tower to fuel gas conditioning is at least $186, 985/ton. Relatively to operation with a spray tower alone, the incremental cost of adding fuel gas conditioning exceeds $400,000/ton.

Based on cost effectiveness grounds, spray tower technology and fuel gas conditioning are eliminated as BART for refinery heaters. As summarized in Table 3-10, BP proposes that good operating practices are BART for SO2 emissions from BART-eligible refinery heaters.

## 3.3 PARTICULATE MATTER (PM10/PM2.5)

Particulate matter emissions from gaseous fuel combustion are inherently low. As tested, PM is comprised of filterable and condensable fractions. According to AP-42, the ratio of condensable to filterable is approximately 3:1 for gaseous fuels.[8] The filterable portion exists in either the solid or liquid state. Condensable particulate matter exists as a gas in the stack but condenses in the cooler ambient air to form PM10/PM2.5. There are several methods for removing particulate from flue gas streams.

### 3.3.1 Step 1: All Available Retrofit PM10/PM2.5 Emission Control Techniques

A review of the current PM10/PM2.5 control technologies was conducted and those technologies that were determined to be commercially available for a retrofit on existing refinery heaters are listed in Table 3-11. Table 3-11 also lists a brief description of each technology.

A review of the RBLC database and control technology literature was performed to find available technologies to control particulate emissions from refinery heaters. The control methods listed generally fell into three categories: use of low sulfur gaseous fuel; good combustion practices; and proper design and operation. No add-on control technologies were found.

### 3.3.2 Step 2: Eliminate Technically Infeasible Options

Each of the potential PM10/PM2.5 control technologies listed in Step 1 were evaluated to determine if they are technically feasible for the BART heaters at Cherry Point.

**<u>Baghouse/Fabric Filter</u>**

In a fabric filter, flue gas is passed through a tightly woven or felted fabric, causing particulate matter in the flue gas to be collected on the fabric and the resulting collected particulate (called cake) by sieving and other mechanisms. Most of the particle collection is performed by the filter cake itself. Fabric filters may be in the form of sheets, cartridges, or bags, with a number of the individual fabric filter units housed together in a group.

[8] AP-42, Section 1.4, Table 1.4-2 (7/98)

As was discussed above, particulate matter emissions are made up of two fractions: filterable and condensable. Due to the relatively high proportion of condensable particulate matter emissions (approximately 72% condensable according to AP-42[9]), the majority of combustion particulate matter will not be collected by a fabric filter treating the flue gas. Also, due to the low particulate concentration, a cake will be slow to form resulting in poor collection efficiency. The low collection efficiency for gas fired units, the requirement for cooling of gas streams to capture the condensable component, and the small particle size all make implementing baghouse control on refinery heaters impractical.

**Dry Electrostatic Precipitator**

In a dry ESP, The flue gas is introduced into an electric field that imparts a charge on the suspended particulate. The charged particulate then migrates to the charged plates where it is collected within the electrostatic precipitator (ESP). The low particulate concentration from gaseous fuel combustion would not allow significant charge buildup on the particles, resulting in poor migration to the collecting plates. Based on this issue, dry ESPs were considered technically infeasible.

**Wet Gas Scrubbing**

The flue gas is introduced into a chamber filled with packing material that provides a large surface area for liquid-particle contact. Scrubbing liquid is evenly introduced above the packing and flows down through the bed. The liquid coats the packing and establishes a thin film. The particulate in the flue gas is extracted when it impacts the thin film of the scrubbing liquid. The spent scrubbing liquid must be treated and disposed of.

When the flue gas follows the tortuous path around the packing material, the inertia of the entrained particulate causes the particles to fall out of the gas flow and impact the thin film of scrubbing liquid. The fine particulate generated from gaseous fuel combustion has little inertia so that the particles follow the gas stream through the packing without impacting the scrubbing liquid and being collected. Therefore, wet scrubbers are not a suitable control technology for application to gas fired refinery heaters and were eliminated based on technical infeasibility.

[9] AP-42, Section 1.4, Table 1.4-2 (7/98)

**Cyclone**

Cyclones use inertia to remove particles from the gas stream. The cyclone imparts centrifugal force on the gas stream, usually within a conical shaped chamber. Particles in the gas stream are forced toward the cyclone walls by the centrifugal force of the spinning gas. The collected particulate must be treated and disposed of as appropriate. The centrifugal force on the small particles resulting from gaseous fuel combustion is insufficient to separate them from the gas stream; the particulate follows the gas stream through the cyclone. Therefore, cyclones are not a suitable control technology for application to refinery heaters and were eliminated based on technical infeasibility.

Two options, fuel gas conditioning and wet electrostatic precipitators (WESP), are considered technically feasible.

### 3.3.3 Step 3: Evaluate Control Effectiveness of Remaining PM10/PM2.5 Control Technologies

The primary focus of the fuel gas conditioning project at the Cherry Point refinery would be to remove sulfur. Reducing sulfur in the fuel gas would also reduce SO2 emissions from combustion sources. SO2 emissions can convert to sulfate particulate usually collected in the back half of the particulate sampling train (i.e., in the condensables).With a reduction in fuel gas sulfur content, there would be a reduction in particulate emissions.

Based on 89% sulfur removal, Jacobs estimates that fuel gas conditioning will result in a 25% reduction in particulate emissions from the refinery heaters. For the wet electrostatic precipitator (ESP), the most stringent control effectiveness was considered to be 90% control. Utilizing both fuel gas conditioning and a wet ESP is assumed to be essentially additive: the fuel gas conditioning brings the particulate emissions down by 25% and then the wet ESP removes 90% of the generated PM10/PM2.5.

Based on this analysis, the remaining technologies for the heaters in decreasing order of effectiveness are:

- Fuel gas conditioning + Wet ESP (92.5% overall control)
- Wet ESP (90% control)
- Fuel gas conditioning (25% control)

### 3.3.4 Step 4: Evaluate Impacts and Document the Results

Five aspects were included in this analysis: costs of compliance, energy impacts, non-air quality environmental impacts, collateral emissions impacts, and remaining useful life. This analysis was performed consistent with the NOx analysis.

**Cost of Compliance**

BP performed this BART analysis for the add-on control devices based on an annualized capital and operating a budgetary level cost (ROM ± 50%) addressing both installation and annual operating costs. The operating costs were estimated based on experience with several existing hydro desulfurization units and general assumptions regarding the operating and maintenance costs for the fuel gas conditioning project. Due to the result of the analysis, a more refined cost analysis was deemed not required to make the BART determination.

**Energy Impacts**

Electricity is used to generate the primary collection mechanism in a wet ESP. In addition, a wet ESP will require an additional fan along with other pumps and equipment requiring electricity. The electricity costs, based on estimates provided by the BP Energy Specialist, were included in the BART cost analysis.

Any additional electrical, amine system, and steam needs due to the installation of the fuel gas conditioning project were not addressed in this budgetary cost estimate. If fuel gas conditioning had been selected as the BART control, refined cost estimates would have been developed.

**Non-air Quality Environmental Impacts**

The wet ESP neutralizing agent and collected particulate will generate a waste stream that will require treatment and disposal. The cost for waste disposal is included in the BART cost analysis. It is assumed that the existing effluent (wastewater treatment) plant will be able to handle the entrained solids in the waste stream.

The fuel gas conditioning acts to remove sulfur compounds from the fuel gas stream which results in a reduction of particulate matter emissions. This sulfur stream will be treated by the Sulfur Recovery Unit (SRU). Jacobs estimates that this additional sulfur removal will result in approximately one ton of additional load per day total to be treated by the SRU.

**Collateral Emissions**

Wet ESPs would not be expected to have any collateral emissions of criteria pollutants. However, with the additional water vapor in the exhaust, the plume can become visible which can create a public perception issue.

Fuel gas conditioning has the potential to reduce multiple pollutants (i.e., SO2 and PM10/PM2.5). This analysis assumes that fuel gas conditioning will be installed to control one primary pollutant. As such, the full cost of fuel gas conditioning is utilized in the BART determination analysis for both SO2 and PM10/PM2.5.

Fuel gas conditioning would require additional steam and an amine treating system, thereby potentially increasing emissions from the refinery boilers. Also, due to the additional load on the SRU, fuel gas conditioning would be expected to increase emissions from the SRU.

**Remaining Useful Life**

As with the NOx analysis, the remaining useful life of all refinery heaters and control devices was assumed to be 20 years.

#### *3.3.4.1 BART for PM10/PM2.5 for Refinery Heaters*

Both fuel gas conditioning and WESPs are considered technically feasible for refinery heaters. The BART cost analyses to install WESPs, fuel gas conditioning, and the combination of the two on each of the BART refinery heaters are included in Tables E-1 to E-31 in Appendix E. The annual and incremental cost effectiveness values are summarized in Table 3-12.

Fuel gas conditioning would reduce $PM_{10}$/PM2.5 emissions from all heaters, both BART and non-BART, whereas a WESP could be applied to each heater individually. The costs for fuel gas conditioning were divided among BART-eligible heaters in proportion to the mass of $PM_{10}$/PM2.5 emission reduction that occurred for each heater.

At a cost of $323,896/ton, fuel gas conditioning is not cost-effective. WESPs and the combination of the two technologies fall outside the range of being cost-effective with values ranging from $228,640/ton to $767,004/ton for the WESP alone and $309,681/ton to $833,361/ton for the combination.

Table 3-12 indicates the incremental cost of installing a WESP to fuel gas conditioning is at least $192,000/ton. Relatively to operation with a WESP alone, the incremental cost of adding fuel gas conditioning exceeds $3 million/ton.

Based on cost effectiveness grounds, WESPs and fuel gas conditioning are eliminated as BART for refinery heaters. As summarized in Table 3-13, BP proposes that good operating practices are BART for $PM_{10}$/PM2.5 emissions from BART-eligible refinery heaters.

# 4.0 BART DETERMINATION ANALYSIS – FLARES

The Cherry Point Refinery maintains two flares that are subject to BART: a high pressure flare (HP Flare) and a low pressure flare (LP Flare). These flares control refinery vent emissions during normal operation and emergencies. As they burn the volatile organic compounds (VOC) and other materials, flares emit NOx, SO2, and PM10/PM2.5, among other pollutants. Because BART is concerned only with normal operation, only emissions during normal operation are considered in this BART analysis.

A flare gas recovery system was installed in 1984 that significantly decreased the total volume of gases sent to the flare. In addition, a coker blowdown vapor recovery system was installed in 2007 that reduced both the volume and sulfur content of the flared gas.

## 4.1 NITROGEN OXIDES (NOX)

Due to the combustion of the support fuel in the pilot light and the combustion refinery gases, flares emit NOx.

### 4.1.1 Step 1: All Available Retrofit Emission Control Techniques

A search of the RBLC database and emission control literature was performed to find available technologies to control flare emissions. In the RBLC, 37 entries were found regarding NOx emissions from refinery flares. Several control methods were listed: "limit fuel to pipeline grade natural gas"; "proper operation and maintenance"; "operate in accordance with 40 CFR 60.18, general control device requirements"; and "proper equipment design and operation, good combustion practices, and use of gaseous fuels". No add-on control technologies were found or are known to be in commercial use. All of the listed control methods are to promote the proper operation of the flare, thereby increasing the destruction efficiency and reducing the amount of NOx emitted.

### 4.1.2 Step 2: Eliminate Technically Infeasible Options

All of the listed control methods found in the RBLC search are technically feasible for the Cherry Point flares. No add-on controls were considered for BART.

### 4.1.3 BART for NOx for the Flares

BP proposes that good operation and maintenance, including use of the flare gas recovery system, limiting pilot light fuel to pipeline grade natural gas and operating in accordance with

40 CFR 60.18, are BART for NOx for the HP and LP Flares. The Cherry Point flares are presently being operated in accordance with these BART controls.

## 4.2 SULFUR DIOXIDE (SO2)

SO2 emissions from flares primarily result from the combustion of sulfur-containing gases vented from the refinery processes. A minor contributor to SO2 emissions from the flares is the natural gas combustion of the pilot flame.

### 4.2.1 Step 1: All Available Retrofit Emission Control Techniques

A search of the RBLC database and emission control literature was performed to find available technologies to control SO2 from flare emissions. In the RBLC, 96 entries were found regarding control of SO2 from flares. Several categories of controls were listed: maintaining flared gas parameters (e.g., heat content, composition, velocity) to allow for good combustion; good practices; meets 40 CFR 60.18; proper design including knock-out pot and seal drum; monitor for continuous presence of flame; and limit on sulfur content of feedstock and fuels (i.e., pollution prevention). No add-on control technologies were found or are known to be in commercial use. Most of the listed controls are to promote the destruction efficiency of the flare. However, only one, pollution prevention, would reduce overall SO2 emissions from a flare.

Pollution prevention measures involve process controls that reduce the sulfur content of the flare feed. The process controls include the use of low-sulfur fuel burned at the flare or a reduction in sulfur content of a feedstock for a process upstream of the flare.

### 4.2.2 Step 2: Eliminate Technically Infeasible Options

Both promoting destruction efficiency and pollution prevention (i.e., reducing the sulfur content of the flared gas) are technically feasible at the Cherry Point refinery.

### 4.2.3 BART for SO2 for the Flares

BP has performed several projects in the recent past to reduce the sulfur content in the flare feed gas. However, because the primary function of flaring is to control upset and emergency releases, the flare projects performed by BP focus mainly on these upset and emergency releases that are outside the purview of BART.

At one point, coker blowdown gases were partially recovered and mixed with refinery fuel gas. The remainder was sent to the flares. A piping change was made to take advantage of existing

compressors to recover more coker blowdown and send less to the flares. More recently, an additional project recovered the remaining coker blowdown. After this change, no coker blowdown gases are sent to the flares except under emergency conditions. This reduced actual SO2 emissions from the flare by 105.6 tons per year.

BP proposes that using good operating practices to promote the destruction efficiency and the existing projects to reduce the sulfur content in the flare feed gas are BART for SO2 emissions from the HP and LP Flares.

## 4.3 PARTICULATE MATTER (PM10/PM2.5)

Due to the combustion of the support fuel in the pilot light and the combustion of refinery gases, flares emit small quantities of particulate matter (PM10/PM2.5).

### 4.3.1 Step 1: All Available Retrofit Emission Control Techniques

A search of the RBLC database and emission control literature was performed to find available technologies to control flare emissions. In the RBLC, 15 entries were found regarding control of particulate matter for refinery flares. Two categories of control methods were listed: proper equipment design and operation with good combustion practices and use of an assisted smokeless flare design. No add-on control technologies were found or are known to be in commercial use. The listed control categories are to promote the proper operation of the flare, thereby increasing the destruction efficiency and reducing the amount of PM10/PM2.5 emitted.

### 4.3.2 Step 2: Eliminate Technically Infeasible Options

The two listed control methods, good combustion practices and use of an assisted smokeless flare design, are technically feasible for the Cherry Point flares.

### 4.3.3 BART for PM10/PM2.5 for the Flares

BP proposes that good combustion practices and use of an air-assisted smokeless flare design and flare gas recovery are BART for PM10/PM2.5 for the HP and LP Flares. The Cherry Point flares presently utilize a steam-assisted smokeless flare design and are operated in accordance with good combustion practices.

## 5.0 BART DETERMINATION ANALYSIS – SRU & TGU

The Cherry Point Refinery presently operates two sulfur recovery units (SRUs), two tail gas units (TGUs), and an incinerator. The two SRUs and incinerator stack were constructed in 1970 and a TGU was added in 1977. The second TGU was added in 2005. Hence, the two SRUs and the original TGU are subject to the BART program but the second "new" TGU is not.

Generally, sulfur recovery units and tail gas treatment units act to remove hydrogen sulfide from process gas and then combust the remaining H2S to SO2 prior to venting. As such, the primary pollutant from SRUs and TGUs is SO2. However, minor amounts of NOx and PM10/PM2.5 are emitted as by-products from fuel combustion during gas treatment. This analysis reviews control technologies available to control visibility-affecting emissions from the combination of the affected SRUs and TGU.

The SRU is subject to the requirements of 40 CFR 63 Subpart UUU, which specifies 40 CFR 60 Subpart J compliance as a control option. The SRU is currently controlled to this MACT standard and not subject to additional controls.

### 5.1 NITROGEN OXIDES (NOX)

Due to the combustion of refinery fuel gas in the SRU Claus sulfur plants and the combustion in the final incinerator/thermal oxidizer, the sulfur incinerator emits NOx.

#### 5.1.1 Step 1: All Available Retrofit Emission Control Techniques

A search of the RBLC database and control technology literature was performed to find available technologies to control NOx emissions from SRUs and TGUs. In the RBLC, 24 entries were found regarding NOx control for SRUs and TGUs at refineries. Two categories of control methods for NOx were listed: good operating practices (e.g., "proper equipment design and operation, good combustion practices, and use of gaseous fuels", "optimized air-fuel ratio", "good operating practices") and use of low NOx burners. Low NOx burners can be installed either within the SRU itself (usually only as part of the initial design) or in the TGU thermal oxidizer.

A thermal oxidizer was included in the RBLC as a NOx control method for a SRU; however, a thermal oxidizer is far more likely to be used to control H2S, not NOx. As such, a thermal oxidizer is not addressed as a potential NOx control option. No other add-on control

technologies were found or are known to be in commercial use for control of NOx from SRUs or TGUs.

### 5.1.2 Step 2: Eliminate Technically Infeasible Options

The three potential BART control options found in Step 1 – (1) LNB in SRU process, (2) LNB in TGU incinerator, and (3) Good operating practices – were evaluated to determine their technical feasibility.

**LNB in SRU Process**

The SRU converts H2S to SO2 and elemental sulfur using heat to drive the Claus reaction. The heat is provided by the main reaction furnace burner. This burner could potentially be replaced with a LNB to reduce NOx emissions. However, the main reaction furnace burners in the SRUs at the Cherry Point Refinery are side-entering. Changing out the burner with a LNB will increase the flame length potentially causing flame impingement and possible damage to the SRU. Consequently, using a LNB within the SRU process is technically infeasible and eliminated from BART consideration.

**LNB in TGU Incinerator**

The incinerator in the TGU acts to oxidize any of the H2S not treated in the SRU and TGU processes prior to venting to the atmosphere. Utilizing a LNB in TGU incinerators, depending upon the SRU/TGU process, can be BACT for new installations.

However, the BART TGU at the Cherry Point Refinery was installed in 1977 utilizes dated technology not suitable for the installation of a LNB. The existing SRU incinerator is a natural draft design. A LNB is not a direct replacement; it would require addition of a fan, motor, base, power and controls. Without these modifications, a direct burner replacement is not technically feasible. With these modifications, the LNB substitution is not cost-effective.

The only technically feasible, cost-effective control technology for NOx that is applicable to the sulfur incinerator at the Cherry Point Refinery is good operating practice.

### 5.1.3 BART for NOx for the Sulfur Incinerator

BP proposes that its current good operating practices are BART for NOx emissions from the sulfur incinerator.

## 5.2 SULFUR DIOXIDE (SO2)

The purpose of the sulfur incinerator is to remove hydrogen sulfide from process gas to create elemental sulfur. Hydrogen sulfide not removed by the SRUs and the TGU is combusted in the incinerator/thermal oxidizer to be released as SO2. A minor contributor to SO2 emissions from the sulfur incinerator is the combustion of support fuel to drive the reaction and also in the final incinerator/thermal oxidizer.

### 5.2.1 Step 1: All Available Retrofit Emission Control Techniques

A search of the RBLC database and control technology literature was performed to find available technologies to control SO2 emissions from SRUs and TGUs. In the RBLC, 32 entries were found regarding control of SO2 from SRUs and TGUs. Two categories of controls were listed: restricting the support fuel gas sulfur content (e.g., "fuel sulfur content limits as follows: diesel fuel, 0.35% sulfur; natural gas, 0.01% sulfur; liquified petroleum gas, 0.01% sulfur; refinery gas, 168 ppmv H2S") and utilizing a specified additional processing device (e.g., SCOT, tail gas incinerator/thermal oxidizer, selective amine absorbers). One entry was found in the California Air Resources Board BACT Clearinghouse for a sulfur recovery plant at a refinery in the Bay Area Air Quality Management District. This determination lists a SCOT unit with a tail gas thermal oxidizer as the additional processing device for the control method. No add-on control technologies specific to SO2 (e.g., scrubber) were found or are known to be in commercial use.

### 5.2.2 Step 2: Eliminate Technically Infeasible Options

Both restricting support fuel sulfur content and utilizing an additional processing device are technically feasible at the Cherry Point refinery.

### 5.2.3 BART for SO2 for the Sulfur Incinerator

The sulfur incinerator uses uninterruptible natural gas as the support fuel to drive the reaction to completion. Natural gas is very low in sulfur.

The BART TGU is a SCOT unit. The "new" #2 TGU is based on the CANSOLV technology and was installed to provide redundant capacity when the #1 TGU is out of service. BP proposes that operating the SRU in compliance with the MACT standard of 40 CFR 63 Subpart UUU is BART for SO2 emissions from the sulfur incinerator.

## 5.3 PARTICULATE MATTER (PM10/PM2.5)

Due to the combustion of refinery fuel gas in the Claus sulfur plants and in the final incinerator/thermal oxidizer, the sulfur incinerator emits a small amount of PM10/PM2.5.

### 5.3.1 Step 1: All Available Retrofit Emission Control Techniques

A search of the RBLC database and control technology literature was performed to find available technologies to control SRU and TGU PM10/PM2.5 emissions. In the RBLC, 16 entries were found regarding control of particulate matter for SRUs and the tail gas combustion control (e.g., thermal oxidizers, incinerators). Only a few of the listings included a control method for particulate matter; the control methods include good combustion practices (e.g., "proper equipment design and operation, good combustion practices, and use of gaseous fuels", "optimized air-fuel ratio", "good maintenance and operation") and the listing of a thermal oxidizer for a sulfur recovery unit itself. No add-on control technologies specific to particulate matter, such as scrubbers or baghouses, were found or are known to be in commercial use.

### 5.3.2 Step 2: Eliminate Technically Infeasible Options

Both listed control methods, good combustion practices and use of a thermal oxidizer, are technically feasible for the Cherry Point sulfur incinerator.

### 5.3.3 BART for PM10/PM2.5 for the Sulfur Incinerator

BP proposes that the use of good combustion practices and use of the existing thermal oxidizer/incinerator are BART for PM10/PM2.5 emissions from the sulfur incinerator. The Cherry Point sulfur incinerator presently utilizes a thermal oxidizer/incinerator as a final control device; the thermal oxidizer/incinerator is operated in accordance with the optimal equipment design and good combustion practices.

## 6.0 BART DETERMINATION ANALYSIS – GREEN COKE LOADOUT

The Green Coke Load Out system was permitted and constructed as part of the original refinery. The Notice of Construction was approved and revised after August 7, 1977 and the equipment was functionally replaced in 1978 for the #1 & #2 Calciners; however, the equipment still physically exists at the refinery. This equipment would only be used in the event that the calciners are off-line for an extended period of time due to process upset or malfunction. The refinery does not have long-term storage capability of green coke and would use this equipment to export the green coke normally routed to the calciners. Because the green coke loadout would only be used during an upset condition, its operation is outside the purview of BART. From a practical perspective, this emission unit has virtually no effect on Class I visibility because it's only emissions are relatively large particle size fugitive dust.

During the baseline period no green coke was loaded; consequently, there are no baseline emissions. However, the refinery desires to retain this loadout option for possible future use.

## 7.0 BART DETERMINATION ANALYSIS – SOUTH DOCK

The Cherry Point refinery maintains two docks for ship loading and offloading; only the South Dock is subject to BART. In 2001, a vapor combustor was permitted for the South Dock. This vapor combustor was considered BACT for VOC emissions from loading of petroleum products. As these vapors are burned, the vapor combustor emits NOx, SO2, and PM10/PM2.5. These emissions are an unavoidable consequence of a permit requirement to operate the vapor combustor. Because BP has a permit requiring operation of the combustor and because NOx, SO2, and PM10/PM2.5 emissions from the dock are minimal, no further analysis was done for this emission source.

## 8.0 VISIBILITY MODELING

Under Ecology and U.S. Environmental Protection Agency (EPA) rules and guidance, sources subject to BART must conduct visibility modeling analyses to assess the relative merits of different BART control strategies.[10] As discussed in further detail in Appendix F, Geomatrix applied the CALPUFF modeling system to assess visibility impacts. Geomatrix followed a *BART Modeling Protocol* developed by the Idaho Department of Environmental Quality, the Oregon Department of Environmental Quality, and Ecology for BART exemption and BART determination analyses.[11] The *BART Modeling Protocol* is designed to be conservative and will likely result in model predictions that overstate the visibility impacts attributable to baseline emissions and the likely benefits of emission controls to improve visibility.

Nineteen emission units from the BART-eligible unit list developed for BP (see Section 1.1) were considered in this modeling analysis. Simulations of emissions from the BP BART-eligible units were performed for two cases:

- Baseline – The highest calendar day NOx, SO2, and PM10 emissions for each emission unit between 2003 and 2005, inclusive.
- BART – Same as the Baseline, except that NOx emissions were based on LNB on the Diesel HDS Charge Heater and Stabilizer Reboiler; the 1st Stage Hydrocracker Fractionator Reboilers; the R-1 Hydrocracker Reactor Heater.

Emissions from Boilers 1 and 3, which are to be removed by 2010, were excluded from both the Baseline and "With BART" modeling. Geomatrix evaluated visibility with Baseline emissions and "With BART" emissions and compared those results with a hypothetical "natural" background, defined as the 20 percent best visibility days of the year.

Geomatrix summarized the simulations by comparing the number of days where the predicted change in the haze index exceeds 0.5 deciviews (dv) within each Class I area. This is the screening criterion for BART exemption. According to *BART Guidelines*, a change in the haze index less than 0.5 dv when compared to natural conditions does not cause or contribute to impairment of visibility. The modeling indicates that BP has a perceptible effect on visibility

[10] 40 CFR Part 51. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations; Final Rule. pg 39129. July 6, 2005. Appendix Y, "Guideline for Best Available Retrofit Technology Determination" (*BART Guidelines*) details EPA's requirements and guidance for states for conducting BART analyses.

[11] *Modeling Protocol for Washington, Oregon, and Idaho: Protocol for the Application of the CALPUFF Modeling System Pursuant to the Best Available Retrofit Technology (BART) Regulation*. Final Version October 11, 2006.

in five of the Class I areas evaluated. With BART emission reductions, there would be fewer days with perceptible change in visibility (compared with background) at three of the five Class I areas where BP emissions have an effect. The two Class I areas where there is no reduction have very few days of visibility impacts from BP emissions (average one day per year or less).

As recommended by the *BART Guidelines*, Geomatrix also used the 98$^{th}$ percentile change to the daily Haze Index (ΔHI), in units of deciviews (dv), as a visibility metric to assess the significance of results from the two emission cases. The 98$^{th}$ percentiles within each Class I area were estimated from the 8$^{th}$ highest daily value of each year and the 22$^{nd}$ highest daily value in three years. In lay language, Geomatrix identified the change in visibility (compared with background conditions) for the Baseline emissions scenario and the BART emissions scenario, and determined that the BART reductions reduce visibility impacts approximately six percent in all relevant Class I areas. Furthermore, only one of the Class I areas (Olympic National Park) has a 98$^{th}$ percentile impact that is perceptible (i.e., ΔHI exceeding 0.5 dv).

## 9.0 PROPOSED COMPLIANCE PLAN & SCHEDULE

The proposed BART technologies, emission factors, and emission rates are summarized in Tables 3-7, 3-10, and 3-13 for BART-eligible sources. In addition to five recent LNB retrofits that constitute BART, BP proposes to install LNB in the 1st Stage HC Fractionator Reboiler to implement BART.

According to the BART program requirements, the BART controls must be installed within five years of SIP approval or approximately 2015. Generally, refinery process units are on a five-year cycle-ending turnaround cycle; that is, all the units are taken down during a turnaround for significant maintenance and repair once every five years. BP is planning to do the BART control installation during a turnaround to avoid as much production loss as possible. Because turnarounds are busy with the normal maintenance and repair requirements, scheduling a BART control installation crowds the turnaround schedule even further. Planning for these turnarounds begins at least two years in advance, so additional lead time is necessary to incorporate the BART control installation in the schedule. Hence, the SIP will have to be approved incorporating the proposed BART determinations at least two years prior to 1st Stage HC Fractionator Reboiler cycle-ending turnaround.

Assuming the SIP is approved by 2012 to allow for turnaround planning, the installation of the ULNB as BART for the 1st Stage HC Fractionator Reboiler is scheduled for the cycle-ending turnaround in 2014. The No. 1 and No. 3 Boilers will be decommissioned by 2010.

## 10.0 SUMMARY AND PERMITTING IMPLICATIONS

BP proposes that LNB are BART for NOx emissions from six refinery BART sources:

- South Vacuum Heater (LNB installed in 2005);
- 1st Stage HC Fractionator Reboiler (proposed);
- 2nd Stage HC Fractionator Reboiler (LNB installed in 2003);
- R-1 Hydrocracker Reactor Heater (LNB installed in 2006);
- Diesel HDS Charge Heater (LNB installed in 2006); and
- Diesel HDS Stabilizer Reboiler (LNB installed in 2006).

LNB for five of the six units have already been permitted and retrofitted. Prior to installation of LNBs on the sixth unit, the 1st Stage HC Fractionator Reboiler, BP must obtain an Order of Approval to Construct from the Northwest Clean Air Agency. The Order will need to allow for potentially higher CO emissions resulting from installation of LNBs.

No. 1 and No. 3 Boilers will be decommissioned by 2010.

# Tables

# TABLE 1-1
# EQUIPMENT NUMBERS FOR THE BART SOURCES

| BART Source Point Description | BART Source Number[1] | Tag Number[2] |
|---|---|---|
| Crude Charge Heater | 1 | 10-1401 |
| South Vacuum Heater | 34 | 10-1451 |
| Naphtha HDS Charge Heater | 3 | 11-1401 |
| Naphtha HDS Stripper Reboiler | 4 | 11-1402 |
| #1 Reformer Heaters | 5 | 11-1403,4,5,6 |
| Coker Charge Heater (#1 North) | 6 | 12-1401-01 |
| Coker Charge Heater (#2 South) | 7 | 12-1401-02 |
| Diesel HDS Charge Heater | 8 | 13-1401 |
| Diesel HDS Stabilizer Reboiler | 9 | 13-1402 |
| Steam Reforming Furnace #1 - (North H2 Plant) | 10 | 14-1401-01 |
| Steam Reforming Furnace #2 - (South H2 Plant) | 11 | 14-1401-02 |
| R-1 HC Reactor Heater | 12 | 15-1401 |
| R-4 HC Reactor Heater | 13 | 15-1402 |
| 1st Stage HC Fractionator Reboiler | 14 | 15-1451 |
| 2nd Stage HC Fractionator Reboiler | 15 | 15-1452 |
| High Pressure Flare | 18 | 29-2802 |
| Low Pressure Flare | 17 | 29-2801 |
| SRU & TGU (Sulfur Incinerator) | 16 | 17-1482 |
| Green Coke Loadout | - | - |
| South Dock | 45 | |
| Boiler No. 1 | 19 | 30-1601-01 |
| Boiler No. 3 | 21 | 30-1601-03 |

[1] Numbers used in original BART equipment list provided by Ecology.
Corresponds to Emission Point Numbers used in WEDS annual emission inventory.
[2] Equipment numbers used by BP Cherry Point in P&IDs

**TABLE 3-1**
**POTENTIAL NOX CONTROL TECHNOLOGIES FOR REFINERY HEATERS**

| Options/Methods | Description | Potentially Applicable To | Overall Technical Feasibility |
|---|---|---|---|
| Selective Catalytic Reduction (SCR) | Injection of ammonia into a catalyst bed within the flue gas path | All | Yes |
| Low NOx Burners (LNB) | Reducing NOx emissions through burner design | All | Yes |
| Selective Non-Catalytic Reduction (SNCR) | Injection of ammonia directly into the flue gas path at a specific temperature | All | No – Small operating range |
| External Flue Gas Recirculation (FGR) | Flue gas is recirculated via fan and external ducting and is mixed with combustion air stream. | More applicable to boilers. Safety concern with process heaters. | No – Potential safety issues |
| Low Excess Air Operation – CO Control | Reduce excess air level by maintaining CO at minimum threshold using in-situ CO analyzer in the flue gas stream | All | No - Potential safety issues and small operating range |
| Steam Injection | Steam is injected into the root of the flame or directly via the fuel stream which lowers the flame temperature | All | Not feasible except 1st Stage HC Fractionator Reboiler |
| Lower Combustion Air Preheat | Reduce combustion air temperature on systems with air preheat | Units with air preheat | No |
| CETEK - Descale & Coat Tubes | Reduces the firebox temperature by improving heat transfer in applications where the tubes are externally scaled | Units with externally scaled tubes | No |
| Firebox Sealing | Prevent tramp air from entering the firebox by sealing penetrations. | All | Yes – included in baseline |
| Overfire Air | Air is injected into the firebox chamber above the burners | Heater or boilers with multiple levels of burners | No – Not applicable to any Cherry Point source |
| Modify Existing Burners to Improve NOx | Burner tip modification | All | Yes |
| Low Excess Air Operation – Improved Combustion Air Control | Operate continuously at design excess oxygen levels | All | No |

**TABLE 3-2**
**TECHNICAL INFEASIBILITY RATIONALE FOR STEAM INJECTION TO IMPROVE NOx FOR INDIVIDUAL HEATERS**

| Source | Reason for Technical Infeasibility |
|---|---|
| Crude Charge Heater | Steam would reduce heater efficiency and heater stability, minimal NOx reduction |
| South Vacuum Heater | Already has ULNB, relatively insignificant NOx reduction |
| Naphtha HDS Charge Heater | Flame pattern already poor - steam injection would make worse |
| Naphtha HDS Stripper Reboiler | Flame pattern already poor - steam injection would make worse |
| #1 Reformer Heaters | Flame pattern already poor - steam injection would make worse |
| Coker Charge Heater (#1 North) | No field experience for injecting steam in this type of heater, minimal NOx reduction |
| Coker Charge Heater (#2 South) | No field experience for injecting steam in this type of heater, minimal NOx reduction |
| Diesel HDS Charge Heater | Already has ULNB, relatively insignificant NOx reduction |
| Diesel HDS Stabilizer Reboiler | Already has ULNB, relatively insignificant NOx reduction |
| Steam Reforming Furnace #1 - (North H2 Plant) | No field experience for injecting steam in this type of heater, minimal NOx reduction |
| Steam Reforming Furnace #2 - (South H2 Plant) | No field experience for injecting steam in this type of heater, minimal NOx reduction |
| R-1 HC Reactor Heater | Already has ULNB, relatively insignificant NOx reduction |
| R-4 HC Reactor Heater | Would result in poorer flame pattern and worsen flame envelopment |
| 1st Stage HC Fractionator Reboiler | Steam injection is potentially feasible but ULNB is proposed as BART |
| 2nd Stage HC Fractionator Reboiler | Already has LNB, relatively insignificant NOx reduction |

**TABLE 3-3**
**TECHNICAL INFEASIBILITY RATIONALE FOR LOWER COMBUSTION AIR PREHEAT TO IMPROVE NOX FOR INDIVIDUAL HEATERS**

| Source | Reason for Technical Infeasibility |
|---|---|
| Crude Charge Heater | Result in reduction of heater capacity |
| South Vacuum Heater | Result in reduction of heater capacity |
| Naphtha HDS Charge Heater | Not equipped with air preheat |
| Naphtha HDS Stripper Reboiler | Not equipped with air preheat |
| #1 Reformer Heaters | Not equipped with air preheat |
| Coker Charge Heater (#1 North) | Not equipped with air preheat |
| Coker Charge Heater (#2 South) | Not equipped with air preheat |
| Diesel HDS Charge Heater | Not equipped with air preheat |
| Diesel HDS Stabilizer Reboiler | Not equipped with air preheat |
| Steam Reforming Furnace #1 - (North H2 Plant) | Result in reduction of heater capacity |
| Steam Reforming Furnace #2 - (South H2 Plant) | Result in reduction of heater capacity |
| R-1 HC Reactor Heater | Not equipped with air preheat |
| R-4 HC Reactor Heater | Not equipped with air preheat |
| 1st Stage HC Fractionator Reboiler | Result in reduction of heater capacity |
| 2nd Stage HC Fractionator Reboiler | Result in reduction of heater capacity |

**TABLE 3-4**
**TECHNICAL INFEASIBILITY RATIONALE FOR MODIFYING EXISTING BURNERS TO IMPROVE NOX FOR INDIVIDUAL HEATERS**

| Source | Reason for Technical Infeasibility |
|---|---|
| Crude Charge Heater | Modification possible but would not reduce NOx emissions |
| South Vacuum Heater | Already equipped with ULNB – modification not possible |
| Naphtha HDS Charge Heater | Lengthening of flame will cause flame impingement |
| Naphtha HDS Stripper Reboiler | Lengthening of flame will cause flame impingement |
| #1 Reformer Heaters | Modification possible but would not reduce NOx emissions |
| Coker Charge Heater (#1 North) | Already equipped with LNB – modification not possible |
| Coker Charge Heater (#2 South) | Already equipped with LNB – modification not possible |
| Diesel HDS Charge Heater | Already equipped with ULNB – modification not possible |
| Diesel HDS Stabilizer Reboiler | Already equipped with ULNB – modification not possible |
| Steam Reforming Furnace #1 - (North H2 Plant) | No modification possible |
| Steam Reforming Furnace #2 - (South H2 Plant) | No modification possible |
| R-1 HC Reactor Heater | Already equipped with ULNB – modification not possible |
| R-4 HC Reactor Heater | Lengthening of flame will cause flame impingement |
| 1st Stage HC Fractionator Reboiler | Potentially feasible but ULNB is proposed as BART |
| 2nd Stage HC Fractionator Reboiler | Already equipped with LNB – modification not possible |

**TABLE 3-5**

**TECHNICAL FEASIBILITY SUMMARY OF POTENTIAL NOX CONTROLS FOR INDIVIDUAL HEATERS**

| BART Source Point Description | SCR Feasibility | Low NOx Burner Feasibility | SNCR Feasibility | External FGR Feasibility | Lower Excess Air Op. – CO Control Feasibility | Steam Injection Feasibility | Lower Comb. Air Temp. Feasibility | CETEK Coating Feasibility | Firebox Sealing Feasibility | Fuel Biasing Feasibility | Overfire Air Feasibility | Modify Existing Burner Feasibility | Lower Excess Air Op. – Comb. Air Control Feasibility |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Crude Charge Heater | yes | no | Not Technically Feasible | Not Technically Feasible | Not Technically Feasible | no | no | no | Included in Baseline | Not Applicable | Not Applicable | no | Not Applicable |
| South Vacuum Heater | yes | Complete | | | | no | no | no | | | | no | |
| Naphtha HDS Charge Heater | yes | no | | | | no | no | no | | | | no | |
| Naphtha HDS Stripper Reboiler | yes | no | | | | no | no | no | | | | no | |
| #1 Reformer Heaters | yes | no | | | | no | no | no | | | | no | |
| Coker Charge Heater (#1 North) | yes | yes | | | | no | no | no | | | | no | |
| Coker Charge Heater (#2 South) | yes | yes | | | | no | no | no | | | | no | |
| Diesel HDS Charge Heater | yes | Complete | | | | no | no | no | | | | no | |
| Diesel HDS Stabilizer Reboiler | yes | Complete | | | | no | no | no | | | | no | |
| Steam Reforming Furnace #1 - (North H2 Plant) | yes | yes | | | | no | no | no | | | | no | |
| Steam Reforming Furnace #2 - (South H2 Plant) | yes | yes | | | | no | no | no | | | | no | |
| R-1 HC Reactor Heater | yes | Complete | | | | no | no | no | | | | no | |
| R-4 HC Reactor Heater | yes | yes | | | | no | no | no | | | | no | |
| 1st Stage HC Fractionator Reboiler | yes | yes | | | | yes | no | no | | | | yes | |
| 2nd Stage HC Fractionator Reboiler | yes | Installed | | | | no | no | no | | | | no | |

# TABLE 3-6
## SUMMARY OF COSTS DEVELOPED FOR BART DETERMINATION FOR NOX FOR REFINERY HEATERS

| Tag | Source | Baseline Fired Duty (MMBtu/hr) | Baseline NOx tons/year | NOx Controlled Emission Factors (lb/MMBtu) | | | NOx Controlled Emissions (tons/year) | | | NOx Emission Reduction (tons/year) | | | Total Annual Cost ($MM)[1] | | | NOx Control Cost Effectiveness ($/ton)[1] | | | Incremental $/ton | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | ULNB (3) | SCR (4) | ULNB + SCR | ULNB | SCR | ULNB + SCR | ULNB | SCR | ULNB + SCR | ULNB | SCR[(4)] | ULNB + SCR | ULNB | SCR | ULNB + SCR | ULNB to SCR | SCR to SCR + ULNB |
| 10-1401 | Crude Charge Heater | 593 | 481 | technically infeasible | 0.0093 | technically infeasible | - | 24.0 | - | - | 456.6 | - | - | **14.6** | - | - | **32,001** | - | - | - |
| 10-1451 | South Vacuum Heater | 186 | 32 | already installed | 0.0060 | - | - | 4.9 | - | - | 27.0 | - | - | 2.2 | - | - | 82,643 | - | - | - |
| 11-1401 | Naphtha HDS Charge Heater | 106 | 45 | technically infeasible | 0.0060 | technically infeasible | - | 2.8 | - | - | 42.7 | - | - | 1.4 | - | - | 32,175 | - | - | - |
| 11-1402 | Naphtha HDS Stripper Reboiler | 64 | 28 | technically infeasible | 0.0060 | technically infeasible | - | 1.7 | - | - | 25.8 | - | - | 1.1 | - | - | 40,711 | - | - | - |
| 11-1403/6 | #1 Reformer Heaters | 709 | 466 | technically infeasible | 0.0075 | technically infeasible | - | 23.3 | - | - | 442.8 | - | - | **7.7** | - | - | **17,299** | - | - | - |
| 12-1401-1 | Coker Charge Heater (#1 North) | 143 | 39 | 0.035 | 0.0060 | 0.0060 | 21.9 | 3.7 | 3.7 | 16.9 | 35.0 | 35.0 | 0.5 | 1.2 | 1.5 | 31,301 | 35,202 | 43,460 | 38,832 | (2) |
| 12-1401-2 | Coker Charge Heater (#2 South) | 145 | 39 | 0.035 | 0.0060 | 0.0060 | 22.3 | 3.8 | 3.8 | 17.2 | 35.7 | 35.7 | 0.5 | 1.2 | 1.5 | 30,762 | 34,597 | 42,738 | 38,164 | (2) |
| 13-1401 | Diesel HDS Charge Heater | 34 | 5 | already installed | 0.0060 | - | - | 0.9 | - | - | 3.7 | - | - | 1.0 | - | - | 282,388 | - | - | - |
| 13-1402 | Diesel HDS Stabilizer Reboiler | 56 | 7 | already installed | 0.0060 | - | - | 1.5 | - | - | 5.4 | - | - | 1.1 | - | - | 206,592 | - | - | - |
| 14-1401 | Reforming Furnace #1 - (North H2 Plant) | 308 | 132 | 0.055 | 0.0060 | 0.0060 | 74.1 | 8.1 | 8.1 | 58.0 | 124.0 | 124.0 | **1.8** | **5.8** | **6.8** | **31,430** | **46,449** | **55,197** | 59,622 | (2) |
| 14-1402 | Reforming Furnace #2 - (South H2 Plant) | 302 | 130 | 0.055 | 0.0060 | 0.0060 | 72.7 | 7.9 | 7.9 | 56.8 | 121.6 | 121.6 | **1.8** | **5.8** | **6.8** | **32,045** | **47,320** | **56,242** | 60,719 | (2) |
| 15-1401 | R-1 HC Reactor Heater | 89 | 8 | already installed | 0.0060 | - | - | 2.3 | - | - | 5.5 | - | - | 1.2 | - | - | 214,726 | - | - | - |
| 15-1402 | R-4 HC Reactor Heater | 42 | 18 | technically infeasible | 0.0060 | technically infeasible | - | 1.1 | - | - | 16.9 | - | - | 0.6 | - | - | 36,620 | - | - | - |
| 15-1451 | 1st Stage HC Fractionator Reboiler | 173 | 114 | 0.050 | 0.0075 | 0.0060 | 37.9 | 5.7 | 4.5 | 75.8 | 108.0 | 109.1 | 0.9 | 2.1 | 2.6 | **12,044** | 19,470 | 23,518 | 36,945 | 402,903 |
| 15-1452 | 2nd Stage HC Fractionator Reboiler | 145 | 36 | 0.045 | 0.0060 | 0.0060 | 28.5 | 3.8 | 3.8 | 7.6 | 32.3 | 32.3 | 0.3 | 1.2 | 1.3 | 36,395 | 37,810 | 40,768 | 38,245 | (2) |

Notes:

(1) The bolded values are those unit/control pairings where a refined Select analysis was performed. An Appraise level analysis was used for all the nonbolded values

(2) A number cannot be generated because the amount of emissions does not change (i.e. the denominator equals 0)

(3) The controlled emission factors for the ULNB are based on the greater of the two vendor guarantees. The 1st Stage HC Fractionator Reboiler is based on the vendor guarantee plus a safety factor.

(4) The controlled emission factor for the SCR based on a control efficiency of 95% or 5 ppm, whichever results in greater emissions

# TABLE 3-7
# PROPOSED BART NOX CONTROL FOR REFINERY HEATERS

| Tag | Source | Proposed BART Technology for NOx | Baseline Fired Duty (MMBtu/hr) | NOx Emission Factor (lb/MMBtu) | NOx Emission Rate | | |
|---|---|---|---|---|---|---|---|
| | | | | | (lb/hr) | (lb/day)[1] | (tons/yr)[2] |
| 10-1401 | Crude Charge Heater | Good practices | 593 | 0.185 | 109.7 | 2634 | 481 |
| 10-1451 | South Vacuum Heater | Existing ULNB | 186 | 0.039 | 7.3 | 174 | 32 |
| 11-1401 | Naphtha HDS Charge Heater | Good practices | 106 | 0.098 | 10.4 | 249 | 45 |
| 11-1402 | Naphtha HDS Stripper Reboiler | Good practices | 64 | 0.098 | 6.3 | 151 | 28 |
| 11-1403/6 | #1 Reformer Heaters | Good practices | 709 | 0.150 | 106.4 | 2554 | 466 |
| 12-1401-1 | Coker Charge Heater (#1 North) | Good practices | 143 | 0.062 | 8.9 | 212 | 39 |
| 12-1401-2 | Coker Charge Heater (#2 South) | Good practices | 145 | 0.062 | 9.0 | 216 | 39 |
| 13-1401 | Diesel HDS Charge Heater | Existing ULNB | 34 | 0.031 | 1.0 | 25 | 5 |
| 13-1402 | Diesel HDS Stabilizer Reboiler | Existing ULNB | 56 | 0.028 | 1.6 | 38 | 7 |
| 14-1401 | Reforming Furnace #1 - (North H2 Plant) | Good practices | 308 | 0.098 | 30.2 | 724 | 132 |
| 14-1402 | Reforming Furnace #2 - (South H2 Plant) | Good practices | 302 | 0.098 | 29.6 | 710 | 130 |
| 15-1401 | R-1 HC Reactor Heater | Existing ULNB | 89 | 0.020 | 1.8 | 43 | 8 |
| 15-1402 | R-4 HC Reactor Heater | Good practices | 42 | 0.098 | 4.1 | 99 | 18 |
| 15-1451 | 1st Stage HC Fractionator Reboiler | ULNB | 173 | 0.050 | 8.6 | 208 | 38 |
| 15-1452 | 2nd Stage HC Fractionator Reboiler | Existing LNB | 145 | 0.057 | 8.2 | 198 | 36 |

[1] Based on 24 hours of operation per day
[2] Based on 24 hours of operation, 365 days per year.

**TABLE 3-8**
**POTENTIAL SO2 CONTROL TECHNOLOGIES FOR REFINERY HEATERS**

| Options/Methods | Description | Potentially Applicable To | Overall Technical Feasibility |
|---|---|---|---|
| Fuel Gas Conditioning | The removal of sulfur compounds from fuel gas before burned in heaters | Universally applied | Yes |
| Spray Tower Scrubbing | Flue gas contacts circulating caustic that reacts with the SO2 | All | Yes |
| Emerachem EMX | Catalyst absorbs SO2 | All | No – Cannot operate five years between turnarounds |
| Dry Scrubbing | Inject bicarbonate in flue gas stream that reacts with the SO2, products removed in a baghouse | All | No – Cannot operate five years between turnarounds |

# TABLE 3-9
## SUMMARY OF COSTS DEVELOPED FOR BART DETERMINATION FOR SO2 FOR REFINERY HEATERS

| Tag | Source | Baseline Fired Duty (MMBtu/hr) | Baseline SO2 (tons/year) | SO2 Controlled Emission Factors (lb/MMBtu) | | | SO2 Controlled Emissions (tons/year) | | | SO2 Emission Reduction (tons/year) | | | Total Annual Cost ($MM) (1) | | | SO2 Control Cost Effectiveness ($/ton) (1) | | | Incremental $/ton | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Fuel Gas Cond (FGC) (1) | Scrubber (2) | FGC + Scrubber (3) | FGC | Scrubber | FGC + Scrubber | FGC | Scrubber | FGC + Scrubber | FGC | Scrubber | FGC + Scrubber | FGC | Scrubber | FGC + Scrubber | FGC to Scrubber | Scrubber to Scrubber + FGC |
| 10-1401 | Crude Charge Heater | 593 | 87.8 | 0.0037 | 0.0017 | 0.0002 | 9.7 | 4.4 | 0.5 | 78.1 | 83.4 | 87.3 | 1.7 | 10.7 | 12.4 | 22,282 | 128,907 | 141,960 | 1,702,782 | 420,712 |
| 10-1451 | South Vacuum Heater | 186 | 33.7 | 0.0046 | 0.0021 | 0.0002 | 3.7 | 1.7 | 0.2 | 30.0 | 32.0 | 33.5 | 0.7 | 2.0 | 2.6 | 22,282 | 61,590 | 77,539 | 641,811 | 418,130 |
| 11-1401 | Naphtha HDS Charge Heater | 106 | 16.9 | 0.0040 | 0.0018 | 0.0002 | 1.9 | 0.8 | 0.1 | 15.1 | 16.1 | 16.8 | 0.3 | 1.0 | 1.4 | 22,282 | 64,471 | 80,407 | 687,221 | 420,712 |
| 11-1402 | Naphtha HDS Stripper Reboiler | 64 | 10.2 | 0.0040 | 0.0018 | 0.0002 | 1.1 | 0.5 | 0.1 | 9.1 | 9.7 | 10.2 | 0.2 | 0.8 | 1.0 | 22,282 | 87,215 | 102,121 | 1,045,677 | 420,440 |
| 11-1403/6 | #1 Reformer Heaters | 709 | 113.3 | 0.0040 | 0.0018 | 0.0002 | 12.5 | 5.7 | 0.6 | 100.8 | 107.6 | 112.6 | 2.2 | 4.1 | 6.3 | 22,282 | 38,407 | 55,508 | 276,416 | 420,712 |
| 12-1401-1 | Coker Charge Heater (#1 North) | 143 | 34.2 | 0.0060 | 0.0027 | 0.0003 | 3.8 | 1.7 | 0.2 | 30.4 | 32.5 | 34.0 | 0.7 | 1.1 | 1.7 | 22,282 | 33,306 | 50,265 | 196,017 | 412,435 |
| 12-1401-2 | Coker Charge Heater (#2 South) | 145 | 34.8 | 0.0060 | 0.0027 | 0.0003 | 3.8 | 1.7 | 0.2 | 31.0 | 33.1 | 34.6 | 0.7 | 1.1 | 1.7 | 22,282 | 32,733 | 49,743 | 186,985 | 413,006 |
| 13-1401 | Diesel HDS Charge Heater | 34 | 5.4 | 0.0040 | 0.0018 | 0.0002 | 0.6 | 0.3 | 0.0 | 4.8 | 5.1 | 5.4 | 0.1 | 0.9 | 1.0 | 22,282 | 168,330 | 179,151 | 2,324,126 | 410,242 |
| 13-1402 | Diesel HDS Stabilizer Reboiler | 56 | 8.9 | 0.0040 | 0.0018 | 0.0002 | 1.0 | 0.4 | 0.0 | 7.9 | 8.5 | 8.9 | 0.2 | 0.9 | 1.1 | 22,282 | 109,737 | 123,564 | 1,400,645 | 418,839 |
| 14-1401 | Reforming Furnace #1 - (North H2 Plant) | 308 | 49.1 | 0.0040 | 0.0018 | 0.0002 | 5.4 | 2.5 | 0.3 | 43.7 | 46.7 | 48.9 | 1.0 | 4.0 | 5.0 | 22,282 | 86,602 | 101,548 | 1,036,025 | 420,704 |
| 14-1402 | Reforming Furnace #2 - (South H2 Plant) | 302 | 48.2 | 0.0040 | 0.0018 | 0.0002 | 5.3 | 2.4 | 0.3 | 42.9 | 45.8 | 47.9 | 1.0 | 4.0 | 4.9 | 22,282 | 87,850 | 102,740 | 1,055,695 | 420,712 |
| 15-1401 | R-1 HC Reactor Heater | 89 | 14.2 | 0.0040 | 0.0018 | 0.0002 | 1.6 | 0.7 | 0.1 | 12.7 | 13.5 | 14.2 | 0.3 | 0.7 | 1.0 | 22,282 | 53,238 | 69,674 | 510,163 | 420,684 |
| 15-1402 | R-4 HC Reactor Heater | 42 | 6.7 | 0.0040 | 0.0018 | 0.0002 | 0.7 | 0.3 | 0.0 | 6.0 | 6.4 | 6.7 | 0.1 | 0.5 | 0.6 | 22,282 | 79,040 | 94,324 | 916,841 | 420,701 |
| 15-1451 | 1st Stage HC Fractionator Reboiler | 173 | 27.6 | 0.0040 | 0.0018 | 0.0002 | 3.0 | 1.4 | 0.2 | 24.6 | 26.2 | 27.5 | 0.5 | 1.1 | 1.6 | 22,282 | 41,119 | 57,898 | 319,167 | 416,210 |
| 15-1452 | 2nd Stage HC Fractionator Reboiler | 145 | 23.1 | 0.0040 | 0.0018 | 0.0002 | 2.5 | 1.2 | 0.1 | 20.5 | 21.9 | 22.9 | 0.5 | 1.0 | 1.4 | 22,282 | 46,271 | 62,719 | 400,358 | 413,967 |

Notes:

(1) The controlled emission factors for the fuel gas conditioning are based on the reduction of the fuel gas sulfur content to 50 ppm.

(2) The controlled emission factors for the scrubber is based on a 95% SO2 control efficiency.

(3) The controlled emission factors for the combined FGC and Spray Tower assume the controls are essentially additive: the FGC reduces the inlet fuel content to 50 ppm and the spray tower reduces the generated SO2 by 95%.

# TABLE 3-10
# PROPOSED BART FOR SO2 CONTROL FOR REFINERY HEATERS

| Tag | Source | Proposed BART Technology for SO2 | Baseline Fired Duty (MMBtu/hr) | SO2 Emission Factor (lb/MMBtu) | SO2 Emission Rate | | |
|---|---|---|---|---|---|---|---|
| | | | | | (lb/hr) | (lb/day)[1] | (tons/yr)[2] |
| 10-1401 | Crude Charge Heater | Good practices | 593 | 0.034 | 20.0 | 481 | 88 |
| 10-1451 | South Vacuum Heater | Good practices | 186 | 0.041 | 7.7 | 185 | 34 |
| 11-1401 | Naphtha HDS Charge Heater | Good practices | 106 | 0.036 | 3.9 | 93 | 17 |
| 11-1402 | Naphtha HDS Stripper Reboiler | Good practices | 64 | 0.036 | 2.3 | 56 | 10 |
| 11-1403/6 | #1 Reformer Heaters | Good practices | 709 | 0.036 | 25.9 | 621 | 113 |
| 12-1401-1 | Coker Charge Heater (#1 North) | Good practices | 143 | 0.055 | 7.8 | 187 | 34 |
| 12-1401-2 | Coker Charge Heater (#2 South) | Good practices | 145 | 0.055 | 7.9 | 191 | 35 |
| 13-1401 | Diesel HDS Charge Heater | Good practices | 34 | 0.036 | 1.2 | 29 | 5 |
| 13-1402 | Diesel HDS Stabilizer Reboiler | Good practices | 56 | 0.036 | 2.0 | 49 | 9 |
| 14-1401 | Reforming Furnace #1 - (North H2 Plant) | Good practices | 308 | 0.036 | 11.2 | 269 | 49 |
| 14-1402 | Reforming Furnace #2 - (South H2 Plant) | Good practices | 302 | 0.036 | 11.0 | 264 | 48 |
| 15-1401 | R-1 HC Reactor Heater | Good practices | 89 | 0.036 | 3.3 | 78 | 14 |
| 15-1402 | R-4 HC Reactor Heater | Good practices | 42 | 0.036 | 1.5 | 37 | 7 |
| 15-1451 | 1st Stage HC Fractionator Reboiler | Good practices | 173 | 0.036 | 6.3 | 151 | 28 |
| 15-1452 | 2nd Stage HC Fractionator Reboiler | Good practices | 145 | 0.036 | 5.3 | 126 | 23 |

[1] Based on 24 hours of operation per day
[2] Based on 24 hours of operation, 365 days per year.

**TABLE 3-11**
**POTENTIAL PM10/PM2.5 CONTROL TECHNOLOGIES FOR REFINERY HEATERS**

| Options/Methods | Description | Potentially Applicable To | Overall Technical Feasibility |
|---|---|---|---|
| Fuel Gas Conditioning | The removal of sulfur compounds from fuel gas before burned in heaters | Universally applied | Yes |
| Dry Electrostatic Precipitator (ESP) | The flue gas is fed to an electric field that imparts a charge on the particles. The particles then migrate to the charged plates where they are collected | All | No – low particulate concentrations & unsuitable physical parameters |
| Wet Electrostatic Precipitator (WESP) | A spray contactor that circulates a neutralizing agent to react with contained sulfur compounds then fed to a electric grid that enhances coalescing of sub-micron particulates | All | Yes |
| Baghouse/Fabric Filter | The flue gas is passed through a tightly woven or felted fabric, causing particulate matter to be collected on the fabric | All | No – low particulate concentrations & unsuitable physical parameters |
| Wet Gas Scrubbing | The particulate is extracted from the flue gas through contact with a scrubbing liquid in a tower | All | No – low particulate concentrations & unsuitable physical parameters |
| Cyclone | Particulate matter is removed from the flue gas using centrifugal force | All | No – low particulate concentrations & unsuitable physical parameters |

# TABLE 3-12
## SUMMARY OF COSTS DEVELOPED FOR BART DETERMINATION FOR PM10/PM2.5 FOR REFINERY HEATERS

| Tag | Source | Baseline Fired Duty (MMBtu/hr) | Baseline PM10 tons/year | PM10 Controlled Emission Factors (lb/MMBtu) | | | PM10 Controlled Emissions (tons/year) | | | PM10 Emission Reduction (tons/year) | | | Total Annual Cost ($MM) (1) | | | PM10 Control Cost Effectiveness ($/ton)[1] | | | Incremental $/ton | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Fuel Gas Cond (FGC) (1) | Wet Electrostatic Precipitator (WESP) (2) | FGC + WESP (3) | FGC | WESP | FGC + WESP | FGC | WESP | FGC + WESP | FGC | WESP | FGC + WESP | FGC | WESP | FGC + WESP | FGC to WESP | WESP to WESP + FGC |
| 10-1401 | Crude Charge Heater | 593 | 87.8 | 0.0070 | 0.0009 | 0.0007 | 18.1 | 2.4 | 1.8 | 69.7 | 85.3 | 85.9 | 2.0 | 12.2 | 14.2 | 323,896 | 563,011 | 635,014 | 654,978 | 3,227,151 |
| 10-1451 | South Vacuum Heater | 186 | 33.7 | 0.0070 | 0.0009 | 0.0007 | 5.7 | 0.8 | 0.6 | 28.0 | 32.9 | 33.1 | 0.6 | 2.4 | 3.1 | 323,896 | 358,643 | 436,137 | 372,007 | 3,225,928 |
| 11-1401 | Naphtha HDS Charge Heater | 106 | 16.9 | 0.0070 | 0.0009 | 0.0007 | 3.2 | 0.4 | 0.3 | 13.7 | 16.5 | 16.6 | 0.3 | 1.3 | 1.6 | 323,896 | 324,753 | 403,196 | 325,083 | 3,227,151 |
| 11-1402 | Naphtha HDS Stripper Reboiler | 64 | 10.2 | 0.0070 | 0.0009 | 0.0007 | 2.0 | 0.3 | 0.2 | 8.3 | 10.0 | 10.0 | 0.2 | 1.0 | 1.2 | 323,896 | 415,910 | 491,886 | 451,300 | 3,227,022 |
| 11-1403/6 | #1 Reformer Heaters | 709 | 113.3 | 0.0070 | 0.0009 | 0.0007 | 21.6 | 2.9 | 2.2 | 91.6 | 110.4 | 111.1 | 2.3 | 5.9 | 8.3 | 323,896 | 228,640 | 309,681 | 192,003 | 3,227,151 |
| 12-1401-1 | Coker Charge Heater (#1 North) | 143 | 34.2 | 0.0070 | 0.0009 | 0.0007 | 4.4 | 0.6 | 0.4 | 29.9 | 33.6 | 33.8 | 0.5 | 1.5 | 1.9 | 323,896 | 280,792 | 360,317 | 264,213 | 3,223,230 |
| 12-1401-2 | Coker Charge Heater (#2 South) | 145 | 34.8 | 0.0070 | 0.0009 | 0.0007 | 4.4 | 0.6 | 0.4 | 30.4 | 34.2 | 34.4 | 0.5 | 1.5 | 1.9 | 323,896 | 275,961 | 355,624 | 257,524 | 3,223,500 |
| 13-1401 | Diesel HDS Charge Heater | 34 | 5.4 | 0.0070 | 0.0009 | 0.0007 | 1.0 | 0.1 | 0.1 | 4.4 | 5.2 | 5.3 | 0.1 | 0.9 | 1.1 | 323,896 | 767,004 | 833,361 | 937,430 | 3,222,191 |
| 13-1402 | Diesel HDS Stabilizer Reboiler | 56 | 8.9 | 0.0070 | 0.0009 | 0.0007 | 1.7 | 0.2 | 0.2 | 7.2 | 8.7 | 8.8 | 0.2 | 1.0 | 1.2 | 323,896 | 511,621 | 584,990 | 583,823 | 3,226,263 |
| 14-1401 | Reforming Furnace #1 - (North H2 Plant) | 308 | 49.1 | 0.0070 | 0.0009 | 0.0007 | 9.4 | 1.3 | 0.9 | 39.7 | 47.9 | 48.2 | 1.0 | 4.9 | 5.9 | 323,896 | 432,812 | 508,335 | 474,703 | 3,227,147 |
| 14-1402 | Reforming Furnace #2 - (South H2 Plant) | 302 | 48.2 | 0.0070 | 0.0009 | 0.0007 | 9.2 | 1.2 | 0.9 | 39.0 | 47.0 | 47.3 | 1.0 | 4.8 | 5.8 | 323,896 | 438,057 | 513,438 | 481,965 | 3,227,151 |
| 15-1401 | R-1 HC Reactor Heater | 89 | 14.2 | 0.0070 | 0.0009 | 0.0007 | 2.7 | 0.4 | 0.3 | 11.5 | 13.9 | 14.0 | 0.3 | 0.9 | 1.2 | 323,896 | 277,464 | 357,185 | 259,606 | 3,227,137 |
| 15-1402 | R-4 HC Reactor Heater | 42 | 6.7 | 0.0070 | 0.0009 | 0.0007 | 1.3 | 0.2 | 0.1 | 5.4 | 6.5 | 6.6 | 0.1 | 0.6 | 0.7 | 323,896 | 373,449 | 450,576 | 392,508 | 3,227,145 |
| 15-1451 | 1st Stage HC Fractionator Reboiler | 173 | 27.6 | 0.0070 | 0.0009 | 0.0007 | 5.3 | 0.7 | 0.5 | 22.3 | 26.9 | 27.1 | 0.6 | 1.5 | 2.1 | 323,896 | 238,737 | 319,447 | 205,984 | 3,225,018 |
| 15-1452 | 2nd Stage HC Fractionator Reboiler | 145 | 23.1 | 0.0070 | 0.0009 | 0.0007 | 4.4 | 0.6 | 0.4 | 18.7 | 22.5 | 22.6 | 0.5 | 1.4 | 1.9 | 323,896 | 265,500 | 345,458 | 243,040 | 3,223,955 |

Notes:

(1) The controlled emission factors for the fuel gas conditioning are based on the assumption that there will be a 25% reduction in particulate matter emissions due to the reduction of the fuel gas sulfur content.

(2) The controlled emission factors for the WESP are based on a 90% PM10/PM2.5 control efficiency.

(3) The controlled emission factors for the combined FGC and WESP assume the controls are essentially additive: the FGC reduces the inlet particulate matter concentration by 25% and the WESP reduces the remaining particulate by 90%.

# TABLE 3-13
# PROPOSED BART FOR PM10/PM2.5 CONTROL FOR REFINERY HEATERS

| Tag | Source | Proposed BART Technology for PM10/PM2.5 | Baseline Fired Duty (MMBtu/hr) | PM10/PM2.5 Emission Factor (lb/MMBtu) | PM10/PM2.5 Emission Rate | | |
|---|---|---|---|---|---|---|---|
| | | | | | (lb/hr) | (lb/day)[1] | (tons/yr)[2] |
| 10-1401 | Crude Charge Heater | Good practices | 593 | 0.0093 | 5.5 | 132 | 24 |
| 10-1451 | South Vacuum Heater | Good practices | 186 | 0.0093 | 1.7 | 42 | 8 |
| 11-1401 | Naphtha HDS Charge Heater | Good practices | 106 | 0.0093 | 1.0 | 24 | 4 |
| 11-1402 | Naphtha HDS Stripper Reboiler | Good practices | 64 | 0.0093 | 0.6 | 14 | 3 |
| 11-1403/6 | #1 Reformer Heaters | Good practices | 709 | 0.0093 | 6.6 | 158 | 29 |
| 12-1401-1 | Coker Charge Heater (#1 North) | Good practices | 143 | 0.0093 | 1.3 | 32 | 6 |
| 12-1401-2 | Coker Charge Heater (#2 South) | Good practices | 145 | 0.0093 | 1.3 | 32 | 6 |
| 13-1401 | Diesel HDS Charge Heater | Good practices | 34 | 0.0093 | 0.3 | 8 | 1 |
| 13-1402 | Diesel HDS Stabilizer Reboiler | Good practices | 56 | 0.0093 | 0.5 | 12 | 2 |
| 14-1401 | Reforming Furnace #1 - (North H2 Plant) | Good practices | 308 | 0.0093 | 2.9 | 69 | 13 |
| 14-1402 | Reforming Furnace #2 - (South H2 Plant) | Good practices | 302 | 0.0093 | 2.8 | 67 | 12 |
| 15-1401 | R-1 HC Reactor Heater | Good practices | 89 | 0.0093 | 0.8 | 20 | 4 |
| 15-1402 | R-4 HC Reactor Heater | Good practices | 42 | 0.0093 | 0.4 | 9 | 2 |
| 15-1451 | 1st Stage HC Fractionator Reboiler | Good practices | 173 | 0.0093 | 1.6 | 39 | 7 |
| 15-1452 | 2nd Stage HC Fractionator Reboiler | Good practices | 145 | 0.0093 | 1.3 | 32 | 6 |

[1] Based on 24 hours of operation per day
[2] Based on 24 hours of operation, 365 days per year.

# APPENDIX A

# Appendix A: Baseline Emissions

In the BART analysis, both the visibility modeling and the cost effectiveness calculations rely on comparisons of "With BART" emissions with "Baseline" emissions. As discussed in Section 2.4, Ecology guidance indicates the baseline period for cost-effectiveness calculations should be the average actual annual emissions over the two-year period preceding the BART analysis (e.g., 2006-2007). However, with the number of heaters subject to BART and the complexity of maintaining two sets of databases throughout the BART analyses, BP elected to apply the same baseline to the cost effectiveness calculations as was applied to the visibility impact assessment. This approach overstates control option cost-effectiveness for heaters because average emissions over a two-year period are obviously much lower than those derived by extrapolating maximum daily emissions over a three year period; this makes the emission reductions appear larger than would actually occur.

This appendix discusses how the baseline emissions were derived for each type of source included in the BART analysis.

**Fired Sources (i.e., Refinery Heaters)**

The emission factors used for the baseline emissions along with their bases are listed in Table A-1. The references include utilizing AP-42 for uncontrolled units, stack test results for tested units, engineering estimates, and use of continuous emission monitoring system (CEMS) data.

The Diesel HDS Charge Heater, Diesel HDS Stabilizer Reboiler, and the R-1 HC Reactor Heater had ultra low NOx burners (ULNB) controls installed since 2005 (i.e., the end of the baseline period). For the purposes of the modeling, the baseline period reflects operation between 2003 and 2005. Consequently, the ULNB emission rates were not taken into consideration in the modeling of the baseline period. As can be seen in Table A-1, their baseline emissions are based on AP-42.

For the purposes of estimating cost effectiveness, the cost effectiveness calculations are based on the current operation of the units. As such, the emissions are based on the controlled emission factors based on the performance testing stack test results (see Table A-1). The installed ULNBs would not be removed even if the BART cost effectiveness calculation showed that they are not cost-effective.

**Non-Fired Sources**

The baseline emissions for the Sulfur Incinerator, the Green Coke Load Out, and the South Dock are derived from the three-year average of the submitted emission inventory data. Because BART only applies to normal operation and the primary emissions from flares generally result from upsets and emergencies, the baseline emissions for the Flares were calculated utilizing a flare base case that reflects only streams routed to the flares during normal operation.

# TABLE A-1
## BASELINE EMISSIONS FOR BART MODELING AND COST EFFECTIVENESS CALCULATIONS - NOX

| Source | Baseline Fired Duty (MMBtu/hr) | For Modeling Purposes | | | | For Cost Effectiveness Calculation Purposes | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Baseline Emission Factor (lb/MMBtu) | Baseline NOx (lb/hr) | Baseline NOx (tons/year) | Reference | Baseline Emission Factor (lb/MMBtu) | Baseline NOx (lb/hr) | Baseline NOx (tons/year) | Reference |
| Crude Charge Heater | 593 | 0.185 | 109.7 | 481 | Stack Test (Last: 8/22/02) | 0.185 | 109.7 | 481 | Stack Test (Last: 8/22/02) |
| South Vacuum Heater | 186 | 0.039 | 7.3 | 32 | based on CEMS data | 0.039 | 7.3 | 32 | based on CEMS data |
| Naphtha HDS Charge Heater | 106 | 0.098 | 10.4 | 45 | EPA, AP-42 (7/98) | 0.098 | 10.4 | 45 | EPA, AP-42 (7/98) |
| Naphtha HDS Stripper Reboiler | 64 | 0.098 | 6.3 | 28 | EPA, AP-42 (7/98) | 0.098 | 6.3 | 28 | EPA, AP-42 (7/98) |
| #1 Reformer Heaters | 709 | 0.150 | 106.4 | 466 | BP Engineering Estimate | 0.150 | 106.4 | 466 | BP Engineering Estimate |
| Coker Charge Heater (#1 North) | 143 | 0.062 | 8.9 | 39 | Stack Test (Last: 6/9/05) | 0.062 | 8.9 | 39 | Stack Test (Last: 6/9/05) |
| Coker Charge Heater (#2 South) | 145 | 0.062 | 9.0 | 39 | Stack Test (Last: 6/9/05) | 0.062 | 9.0 | 39 | Stack Test (Last: 6/9/05) |
| **Diesel HDS Charge Heater** | **34** | **0.098** | **3.3** | **14** | **EPA, AP-42 (7/98)** | **0.031** | **1.0** | **5** | **EPA, AP-42 (7/98)** |
| **Diesel HDS Stabilizer Reboiler** | **56** | **0.098** | **5.5** | **24** | **EPA, AP-42 (7/98)** | **0.028** | **1.6** | **7** | **EPA, AP-42 (7/98)** |
| Reforming Furnace #1 - (North H2 Plant) | 308 | 0.098 | 30.2 | 132 | EPA, AP-42 (7/98) | 0.098 | 30.2 | 132 | EPA, AP-42 (7/98) |
| Reforming Furnace #2 - (South H2 Plant) | 302 | 0.098 | 29.6 | 130 | EPA, AP-42 (7/98) | 0.098 | 29.6 | 130 | EPA, AP-42 (7/98) |
| **R-1 HC Reactor Heater** | **89** | **0.098** | **8.7** | **38** | **EPA, AP-42 (7/98)** | **0.020** | **1.8** | **8** | **EPA, AP-42 (7/98)** |
| R-4 HC Reactor Heater | 42 | 0.098 | 4.1 | 18 | EPA, AP-42 (7/98) | 0.098 | 4.1 | 18 | EPA, AP-42 (7/98) |
| 1st Stage HC Fractionator Reboiler | 173 | 0.150 | 25.9 | 114 | BP Engineering Estimate | 0.150 | 25.9 | 114 | BP Engineering Estimate |
| 2nd Stage HC Fractionator Reboiler | 145 | 0.057 | 8.2 | 36 | Stack Test (10/04) | 0.057 | 8.2 | 36 | Stack Test (10/04) |
| SRU & TGU (Sulfur Incinerator) | - | - | 1.4 | 6 | Average of 2003, 2004, & 2005 WEDS | - | 1.4 | 6 | Average of 2003, 2004, & 2005 WEDS |
| High Pressure Flare | - | - | 2.6 | 11 | Based on flare base case provided by BP | - | 2.6 | 11 | Based on flare base case provided by BP |
| Low Pressure Flare | - | - | 3.8 | 17 | Based on flare base case provided by BP | - | 3.8 | 17 | Based on flare base case provided by BP |
| Green Coke Loadout | - | - | 0.0 | 0 | Average of 2003, 2004, & 2005 WEDS | - | 0.0 | 0 | Average of 2003, 2004, & 2005 WEDS |
| South Dock | - | - | 6.6 | 29 | Average of 2003, 2004, & 2005 WEDS | - | 6.6 | 29 | Average of 2003, 2004, & 2005 WEDS |

Notes:
The bolded units are those that have had controls installed since 2005.

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# TABLE A-1

## BASELINE EMISSIONS FOR BART MODELING AND COST EFFECTIVENESS CALCULATIONS – SO2

| Tag | Source | Baseline Fired Duty (MMBtu/hr) | For BART Purposes | | | |
|---|---|---|---|---|---|---|
| | | | Baseline Emission Factor (lb/MMBtu) | Baseline SO2 (lb/hr) | Baseline SO2 (tons/year) | Reference |
| 10-1401 | Crude Charge Heater | 593 | 0.0338 | 20.0 | 88 | Based on Source Tests |
| 10-1451 | South Vacuum Heater | 186 | 0.0413 | 7.7 | 34 | Based on Source Tests |
| 11-1401 | Naphtha HDS Charge Heater | 106 | 0.0364 | 3.9 | 17 | Based on Sulfur Mass Balance |
| 11-1402 | Naphtha HDS Stripper Reboiler | 64 | 0.0364 | 2.3 | 10 | Based on Sulfur Mass Balance |
| 11-1403/6 | #1 Reformer Heaters | 709 | 0.0364 | 25.9 | 113 | Based on Sulfur Mass Balance |
| 12-1401-1 | Coker Charge Heater (#1 North) | 143 | 0.0547 | 7.8 | 34 | Based on Source Tests |
| 12-1401-2 | Coker Charge Heater (#2 South) | 145 | 0.0547 | 7.9 | 35 | Based on Source Tests |
| 13-1401 | Diesel HDS Charge Heater | 34 | 0.0364 | 1.2 | 5 | Based on Sulfur Mass Balance |
| 13-1402 | Diesel HDS Stabilizer Reboiler | 56 | 0.0364 | 2.0 | 9 | Based on Sulfur Mass Balance |
| 14-1401 | Reforming Furnace #1 - (North H2 Plant) | 308 | 0.0364 | 11.2 | 49 | Based on Sulfur Mass Balance |
| 14-1402 | Reforming Furnace #2 - (South H2 Plant) | 302 | 0.0364 | 11.0 | 48 | Based on Sulfur Mass Balance |
| 15-1401 | R-1 HC Reactor Heater | 89 | 0.0364 | 3.3 | 14 | Based on Sulfur Mass Balance |
| 15-1402 | R-4 HC Reactor Heater | 42 | 0.0364 | 1.5 | 7 | Based on Sulfur Mass Balance |
| 15-1451 | 1st Stage HC Fractionator Reboiler | 173 | 0.0364 | 6.3 | 28 | Based on Sulfur Mass Balance |
| 15-1452 | 2nd Stage HC Fractionator Reboiler | 145 | 0.0364 | 5.3 | 23 | Based on Sulfur Mass Balance |
| 17-1482 | SRU & TGU (Sulfur Incinerator) | - | - | 8.5 | 37 | Average of 2003, 2004, & 2005 WEDS |
| 29-2802 | High Pressure Flare | - | - | 2.7 | 12 | Based on flare base case provided by BP |
| 29-2801 | Low Pressure Flare | - | - | 4.6 | 20 | Based on flare base case provided by BP |
| - | Green Coke Loadout | - | - | 0 | 0 | Average of 2003, 2004, & 2005 WEDS |
| - | South Dock | - | - | 0 | 0 | Average of 2003, 2004, & 2005 WEDS |

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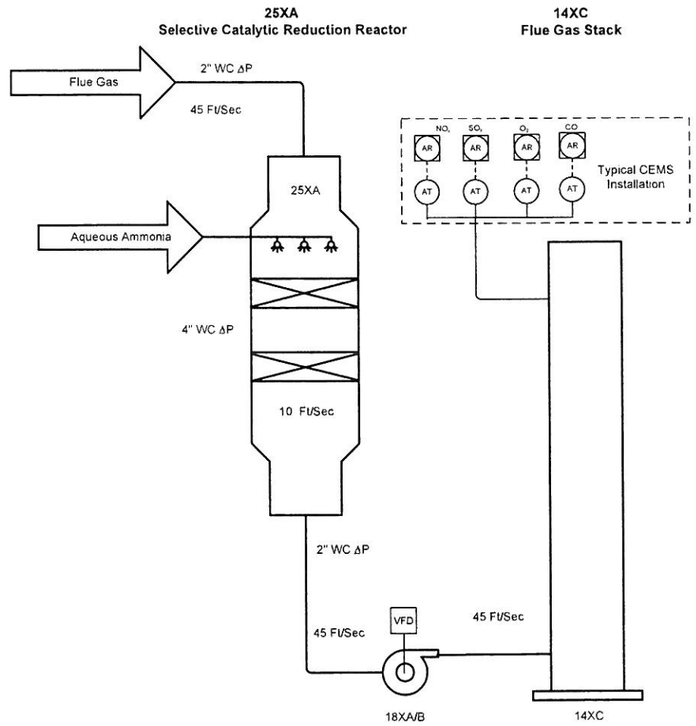
# TABLE A-1

## BASELINE EMISSIONS FOR BART MODELING AND COST EFFECTIVENESS CALCULATIONS – PM10/PM2.5

| Tag | Source | Baseline Fired Duty (MMBtu/hr) | For BART Purposes | | | |
|---|---|---|---|---|---|---|
| | | | Baseline Emission Factor (lb/MMBtu) | Baseline PM10 (lb/hr) | Baseline PM10 (tons/year) | Reference |
| 10-1401 | Crude Charge Heater | 593 | 0.00929 | 5.5 | 24 | Based on Source Tests |
| 10-1451 | South Vacuum Heater | 186 | 0.00929 | 1.7 | 8 | Based on Source Tests |
| 11-1401 | Naphtha HDS Charge Heater | 106 | 0.00929 | 1.0 | 4 | Based on Source Tests |
| 11-1402 | Naphtha HDS Stripper Reboiler | 64 | 0.00929 | 0.6 | 3 | Based on Source Tests |
| 11-1403/6 | #1 Reformer Heaters | 709 | 0.00929 | 6.6 | 29 | Based on Source Tests |
| 12-1401-1 | Coker Charge Heater (#1 North) | 143 | 0.00929 | 1.3 | 6 | Based on Source Tests |
| 12-1401-2 | Coker Charge Heater (#2 South) | 145 | 0.00929 | 1.3 | 6 | Based on Source Tests |
| 13-1401 | Diesel HDS Charge Heater | 34 | 0.00929 | 0.3 | 1 | Based on Source Tests |
| 13-1402 | Diesel HDS Stabilizer Reboiler | 56 | 0.00929 | 0.5 | 2 | Based on Source Tests |
| 14-1401 | Reforming Furnace #1 - (North H2 Plant) | 308 | 0.00929 | 2.9 | 13 | Based on Source Tests |
| 14-1402 | Reforming Furnace #2 - (South H2 Plant) | 302 | 0.00929 | 2.8 | 12 | Based on Source Tests |
| 15-1401 | R-1 HC Reactor Heater | 89 | 0.00929 | 0.8 | 4 | Based on Source Tests |
| 15-1402 | R-4 HC Reactor Heater | 42 | 0.00929 | 0.4 | 2 | Based on Source Tests |
| 15-1451 | 1st Stage HC Fractionator Reboiler | 173 | 0.00929 | 1.6 | 7 | Based on Source Tests |
| 15-1452 | 2nd Stage HC Fractionator Reboiler | 145 | 0.00929 | 1.3 | 6 | Based on Source Tests |
| 17-1482 | SRU & TGU (Sulfur Incinerator) | - | - | 0.2 | 1 | Average of 2003, 2004, & 2005 WEDS |
| 29-2802 | High Pressure Flare | - | - | 0.3 | 1 | Based on flare base case provided by BP |
| 29-2801 | Low Pressure Flare | - | - | 0.4 | 2 | Based on flare base case provided by BP |
| - | Green Coke Loadout | - | - | 0 | 0 | Average of 2003, 2004, & 2005 WEDS |
| - | South Dock | - | - | 0 | 0 | Average of 2003, 2004, & 2005 WEDS |

# APPENDIX B




## 18XA/B
## Induced Draft Fan & Spare

| Input | Crude Charge heater Induced Draft | Crude Charge heater Forced Draft | #1 Reformer | Hydrogen | Hydrogen |
|---|---|---|---|---|---|
| Mw | 27.78 | 28.81 | 27.78 | 27.78 | 27.78 |
| k,cp/cv | 1.35 | 1.41 | 1.35 | 1.35 | 1.35 |
| Zsuction | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Psuction, psia | 14.12 | 14.62 | 14.48 | 14.37 | 14.37 |
| Tsuction, °F | 450.00 | 60.00 | 750.00 | 750.00 | 750.00 |
| Pdischarge, psia | 14.70 | 15.13 | 14.70 | 14.70 | 14.70 |
| Zdischarge | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Isoenthalpic,eff | 0.70 | 0.70 | 0.70 | 0.70 | 0.70 |
| Flow Rate,MMSCFD | 170.72 | 156.60 | 204.16 | 88.58 | 86.85 |
| **Output** | | | | | |
| Density, suction lb/ft³ | 0.04 | 0.08 | 0.03 | 0.03 | 0.03 |
| Ts,°R | 909.70 | 519.70 | 1,209.70 | 1,209.70 | 1,209.70 |
| Tdisch, Pred °F | 463.56 | 67.36 | 756.66 | 760.03 | 760.03 |
| W,Lb/min | 8,678.45 | 8,255.83 | 10,378.36 | 4,502.91 | 4,414.97 |
| W, Lb/Hr | 520,707 | 495,350 | 622,701 | 270,175 | 264,898 |
| r (Pd/Ps) | 1.04 | 1.03 | 1.01 | 1.02 | 1.02 |
| ACFM | 215,972.01 | 109,271.44 | 334,899.15 | 146,397.93 | 143,538.72 |
| MMSCFD | 170.72 | 156.60 | 204.16 | 88.58 | 86.85 |
| Head | 2,036.25 | 950.28 | 999.47 | 1,506.28 | 1,506.28 |
| Gas Horsepower | 765.00 | 339.63 | 449.04 | 293.62 | 287.89 |
| dp, inches w.c. | 16.00 | 14.00 | 6.00 | 9.00 | 9.00 |
| 115% factor, HP | 879.75 | 390.57 | 516.40 | 337.67 | 331.07 |
| Motor with 1.1 factor | 967.72 | 429.63 | 568.04 | 371.43 | 364.18 |
| Nominal Motor Size | 1,000 | 500 | 600 | 400 | 400 |

SCR Design

Design Basis for SCR
95% efficiency, with NOx equal to or greater than 5 ppmvd
5% Ammonia Slip
4 inch w.c. pressure drop
Calculate Catalyst Volume using Jacobs formulae
Catalyst Correction Factor=

$$\text{Catalyst Correction Factor} = 0.08 + \left(\frac{NH3}{NOx}\right) + 0.08\left(\frac{NH3}{NOx}\right)^2 + 0.08\left(\frac{NH3}{NOx}\right)^3 + 0.08\left(\frac{NH3}{NOx}\right)^4 + 0.08\left(\frac{NH3}{NOx}\right)^5$$

Catalyst Activity Facto = 1 - 0.08 • years of run

Catalyst Intrinsic Rate Contstant = $A_o e^{RX/*R}$

Space Velocity, Hr = 3600 * Cat Intrinsic Rate Const • Cat Activity Factor • Spec Surf •
Catalyst Correction Factor/(-ln(1 - eff))

Volume = SpaceVelocity,Hr • ACFH

Cross sectional area based on 10 ft/sec
Calculate length, with minimum of 12 feet

Preheaters
5 inch w.c. pressure drop
Do not allow flue gas to run less than 450°F to avoid Ammonia Bisulphate and Ammonia Sulphate precipitation.

Fans

70% efficiency

Required ammonia

NH3 = Moles NOx + 5 ppmv slip

Catalyst
Use MT catalyst
Operating temperature 550 to 750°F

| BART Source Point Discription | Peak Design MMBTU/Hr | Combustion air MMSCFD | Flue Gas MMSCFD | SCR Inlet °F | ft³/sec | Ducting area, ft² at 45 ft/sec | Ducting Side or Square Duct ft | Reactor area, ft² at 10 ft/sec | Reactor Square duct side ft |
|---|---|---|---|---|---|---|---|---|---|
| Crude Charge Heater | 593.20 | 156.60 | 170.72 | 750 | 4599.3 | 102 | 10.1 | 460 | 21.4 |
| #1 Reformer Heaters | 709.40 | 187.28 | 204.16 | 750 | 5500.2 | 122 | 11.1 | 550 | 23.5 |
| Reforming Furnace #1 - (North H2 Plant) | 307.80 | 81.26 | 88.58 | 632 | 2153.7 | 48 | 6.9 | 215 | 14.7 |
| Reforming Furnace #2 - (South H2 Plant) | 301.80 | 79.67 | 86.85 | 632 | 2111.7 | 47 | 6.9 | 211 | 14.5 |

| BART Source Point Discription | Ducting Downstream of Preheater °F | acfm | area, ft² at 45 ft/sec | Side or Square Duct ft | Ducting Combustion Air °F | area, ft² at 45 ft/sec | area, ft² at 45 ft/sec | Side or Square Duct ft | Ducting Combustion Air °F | area, ft² at 45 ft/sec | area, ft² at 45 ft/sec | Side or Square Duct ft | Ducting Combustion Air °F | area, ft² at 45 ft/sec | area, ft² at 45 ft/sec | Side or Square Duct ft |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Crude Charge Heater | 450 | 3,459 | 76.9 | 8.8 | 60 | 1,813 | 40.3 | 6.3 | 594 | 3,675 | 81.7 | 9.0 | 309 | 2,681 | 59.6 | 7.7 |
| #1 Reformer Heaters | | | | | | | | | | | | | | | | |
| Reforming Furnace #1 - (North H2 Plant) | | | | | | | | | | | | | | | | |
| Reforming Furnace #2 - (South H2 Plant) | | | | | | | | | | | | | | | | |

FILE GENERIC SCR V5D REV 02/21/08 2:30 PM

| NO. | DATE | REVISION DESCRIPTION | BY | CHK | APPD | NO | DATE | REFERENCE DRAWINGS |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | AB-1100-41 |
| | | | | | | | | AR-1100-21 |

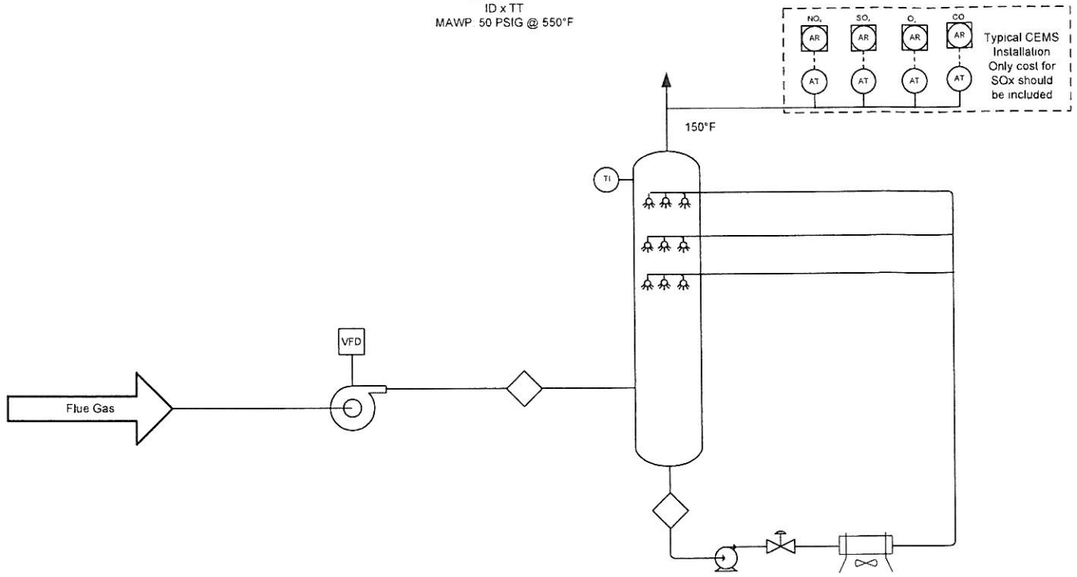
APPROVAL

| ENGINEERING RECORD | | DATE |
|---|---|---|
| DRAWN BY | RAJ | 11/1/07 |
| DESIGNED BY | | |
| DESIGN CHECKED | | |
| APPROVED BY | | |
| APPROVED BY | | |
| WORK PKG | | |
| SCALE | | |

bp BP CHERRY POINT

TITLE OF DRAWING: Generic SCR Option

| PROJECT & MODULE I D | | DRAWING NUMBER | | | | | | SHEET |
|---|---|---|---|---|---|---|---|---|
| – | | SK – | 11 – | XX – | PFD 1 | – 0 | D | 0 0 1 |
| PROJECT | MODULE | DISC | FAC | CONT I D | SEQUENCE NO | REV NO. | | OF |




The following is design information. The install factor is typically the last number in the cost equation. Also note that the cost are for each item ( if two are required then multiply by two ).

$$\text{Fan Cost} = \left[\frac{\text{ACFM}}{100{,}000}\right]^{0.6} * \$100{,}000 * 5$$

$$\text{Fan Motor} = \left[\frac{\text{HP}}{100{,}000}\right]^{0.6} * \$20{,}000 * 4$$

$$\text{Pump} = \left[\frac{\text{GPM}}{100}\right]^{0.6} * \$22{,}500 * 5$$

Use pump efficiency of 50% and use 50 psi of head
Set flowrate based on 20 GPM/Ft²

$$\text{Pump Motor} = \left[\frac{\text{HP}}{100}\right]^{0.6} * \$20{,}000 * 5$$

Ducting
45 ft/sec, calculate surface area and use $75/Ft²

Scrubber
Size based on 10 Ft/Sec gas velocity, at 150°F
T/T length = 80 Feet
Calculate cost at $200/External Surface Area ( Ft² )

Cyclones
Number of cyclones = Separator cross sectional area/100 Ft²
Cost is $10,000/cyclone x 5 (install factor)

XX-
Induced Draft Fan & Spare
XXX HP Motor

FILE SCRUBBER V5 D REV 02/05/08 9:59 AM

| NO | DATE | REVISION DESCRIPTION | BY | CHK | APPD | NO | DATE | REFERENCE DRAWINGS |
|---|---|---|---|---|---|---|---|---|

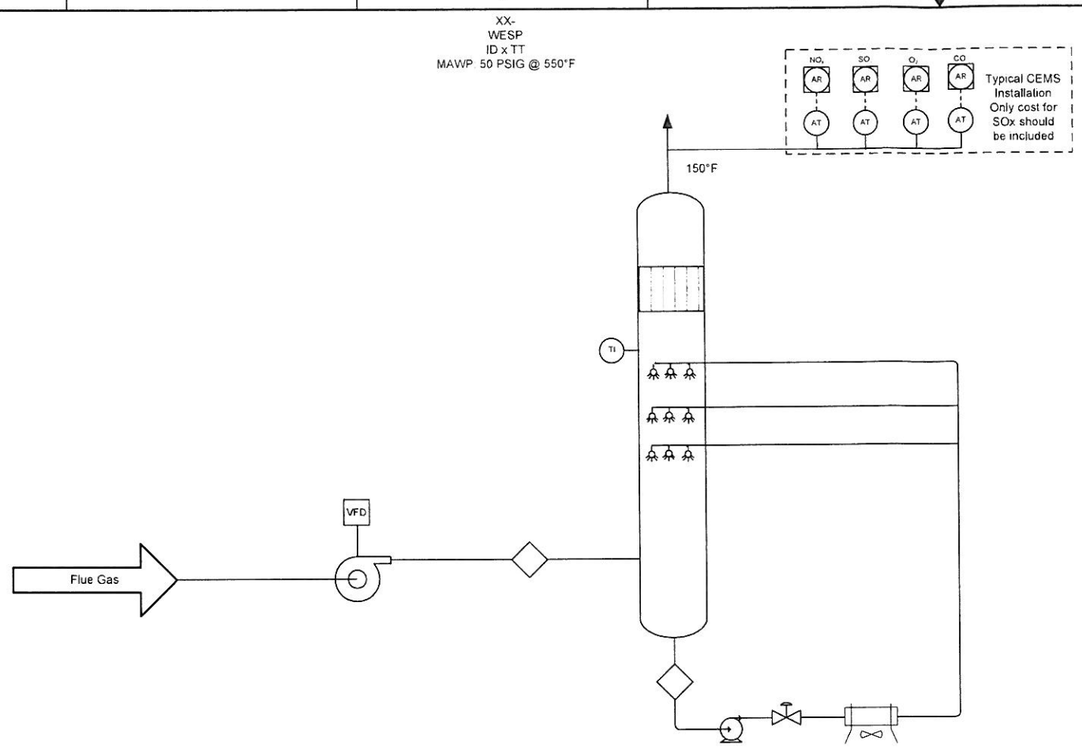
APPROVAL

| ENGINEERING RECORD | | DATE |
|---|---|---|
| DRAWN BY | RAJ | 02/11/08 |
| DESIGNED BY | | |
| DESIGN CHECKED | | |
| APPROVED BY | | |
| APPROVED BY | | |
| WORK PKG | | |
| SCALE | | |

bp
BP CHERRY POINT

TITLE OF DRAWING
SOx Scrubber
Generic Design

| PROJECT & MODULE I.D. | | DRAWING NUMBER | | | | | | SHEET |
|---|---|---|---|---|---|---|---|---|
| — | | SK — | — XX — | PFD 1 | — 0 | D | | 0 0 1 |
| PROJECT | MODULE | DISC | FAC | CONT.I.D | SEQUENCE NO | | REV NO. | OF |




The following is design information. The install factor is typically the last number in the cost equation. Also note that the cost are for each item ( if two are required then multiply by two ).

$$\text{Fan Cost} = \left[\frac{\text{ACFM}}{100{,}000}\right]^{0.6} * \$100{,}000 * 5$$

$$\text{Fan Motor} = \left[\frac{\text{HP}}{100{,}000}\right]^{0.6} * \$20{,}000 * 4$$

$$\text{Pump} = \left[\frac{\text{GPM}}{100}\right]^{0.6} * \$22{,}500 * 5$$

Use pump efficiency of 50% and use 50 psi of head
Set flowrate based on 20 GPM/Ft²

$$\text{Pump Motor} = \left[\frac{\text{HP}}{100}\right]^{0.6} * \$20{,}000 * 5$$

Ducting
45 ft/sec, calculate surface area and use $75/Ft²

Scrubber
Size based on 10 Ft/Sec gas velocity, at 150°F
T/T length = 80 Feet
Calculate cost at $200/External Surface Area ( Ft² )

Cyclones
Number of cyclones = Separator cross sectional area/100 Ft²
Cost is $10,000/cyclone x 5 (install factor)

WESP is costed out at $10/ACFM.
Also 40 feet is added to the length of the scrubber to account for the additional size of the WESP

XX-
Induced Draft Fan & Spare
XXX HP Motor

WESP
FILE SCRUBBER.VS REV. 02/20/08 10:00 AM

| NO | DATE | REVISION DESCRIPTION | BY | CHK | APPD | NO | DATE | REFERENCE DRAWINGS |
|---|---|---|---|---|---|---|---|---|

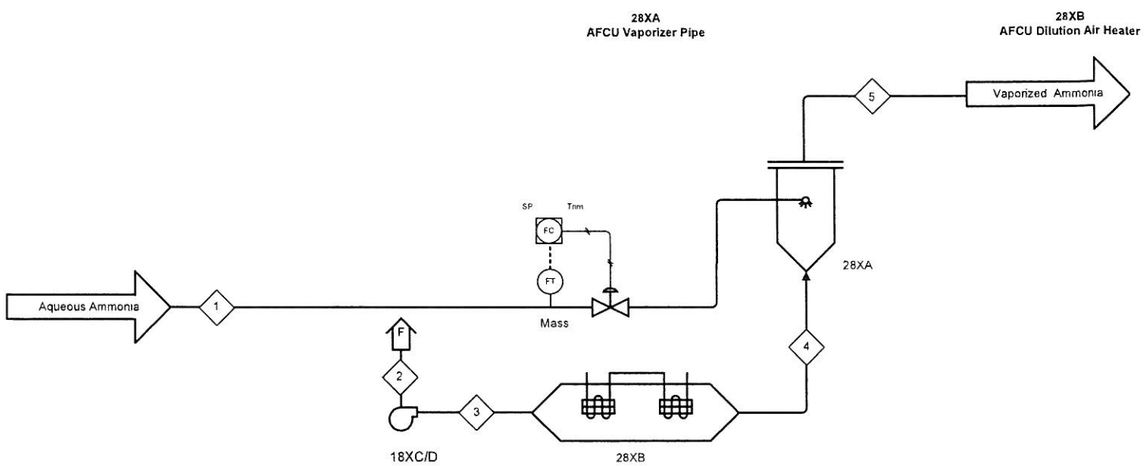
APPROVAL

| ENGINEERING RECORD | | DATE |
|---|---|---|
| DRAWN BY | RAJ | 02/11/08 |
| DESIGNED BY | | |
| DESIGN CHECKED | | |
| APPROVED BY | | |
| APPROVED BY | | |
| WORK PKG | | |
| SCALE | | |

bp
BP CHERRY POINT

TITLE OF DRAWING
WESP & SOx Scrubber
Generic Design

| PROJECT & MODULE I D | | DRAWING NUMBER | | | | | | SHEET |
|---|---|---|---|---|---|---|---|---|
| — | | SK — | — XX — | PFD 1 | — 0 | D | | 0 0 1 |
| PROJECT | MODULE | DISC | FAC | CONT I D | SEQUENCE NO | | REV NO | OF |




Vendor Supplied Ammonia Flow Control Unit (AFCU)

Material Balance for 100 lb/hr Aqueous Ammonia

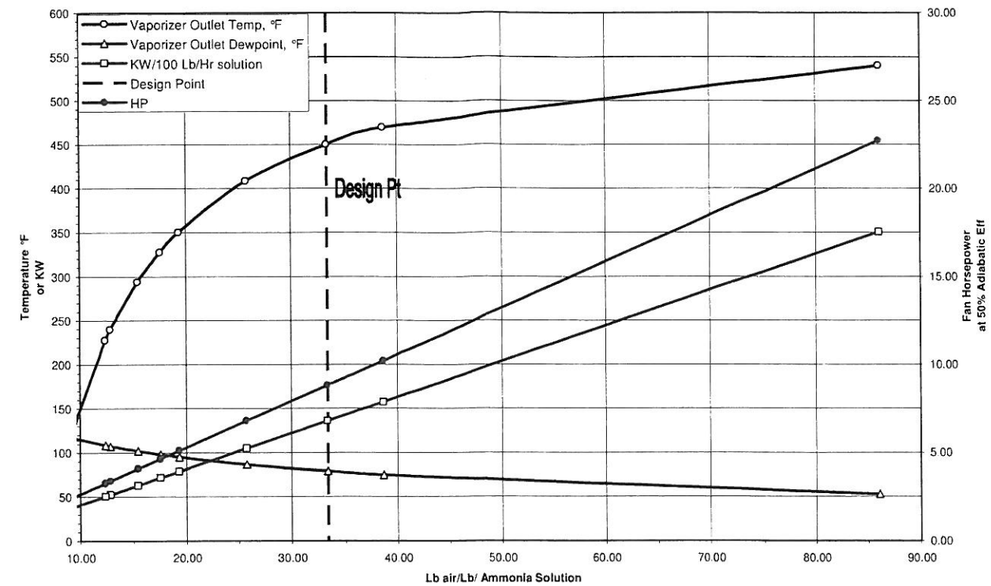
| Number | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| Air, Mole % | 0.00 | 100.00 | 100.00 | 100.00 | 95.33 |
| NH3, Mole % | 30.58 | 0.00 | 0.00 | 0.00 | 1.43 |
| H2O, Mole % | 69.42 | 0.00 | 0.00 | 0.00 | 3.24 |
| Molar Flow lbmole/hr | 5.65 | 115.27 | 115.27 | 115.27 | 120.91 |
| Pressure,psia | 14.70 | 14.70 | 16.32 | 15.20 | 14.70 |
| Temperature °F | 0.00 | 0.00 | 28.52 | 600.00 | 450.01 |
| Vapour Fraction | 0.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Mass Flow lb/hr | 100.00 | 3,337.00 | 3,337.00 | 3,337.00 | 3,437.00 |
| GPM @ 60°F | 0.237 | 7.577 | 7.577 | 7.577 | 7.813 |
| MMBtu/Hr | -0.5479 | -0.0610 | -0.0386 | 0.4249 | -0.1230 |
| Kilowatts | -160.5791 | -17.8852 | -11.3259 | 124.5375 | -36.0416 |
| Mass Density lb/ft3 | 55.61 | 0.0863 | 0.0902 | 0.0387 | 0.0428 |
| Cp/Cv | 1.16 | 1.42 | 1.41 | 1.38 | 1.38 |
| CP ,Btu/lb-°F | 1.12 | 0.24 | 0.24 | 0.25 | 0.25 |
| Viscosity,cp | 1.07 | 0.0167 | 0.0175 | 0.0309 | 0.0267 |
| Thermal Conductivity Btu/hr-ft-°F | 0.32 | 0.0126 | 0.0132 | 0.0245 | 0.0218 |

| Ammonia Injection System | | | | | | | Inlet duct (45 ft/sec) | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Source | lb/hr solution | gpm | Electrical Heater, KW | Electrical Heater, "HP" | Blower HP 50% eff | Dilution air,CFM | Dilution air, ft³/sec | ft² | Diameter duct. Inches | Dilution air, ft³/sec |
| Crude Charge Heater | 135.52 | 0.3043 | 183.90 | 246.42 | 11.92 | 873 | 14.55 | 0.3234 | 7.70 | 13.92 |
| #1 Reformer Heaters | 132.41 | 0.2973 | 179.68 | 240.77 | 11.65 | 853 | 14.22 | 0.3160 | 7.61 | 13.60 |
| Reforming Furnace #1 - (North H2 Plant) | 38.33 | 0.0861 | 52.02 | 69.70 | 3.37 | 247 | 4.12 | 0.0915 | 4.10 | 3.94 |
| Reforming Furnace #2 - (South H2 Plant) | 37.59 | 0.0844 | 51.01 | 68.36 | 3.31 | 242 | 4.04 | 0.0897 | 4.06 | 3.86 |

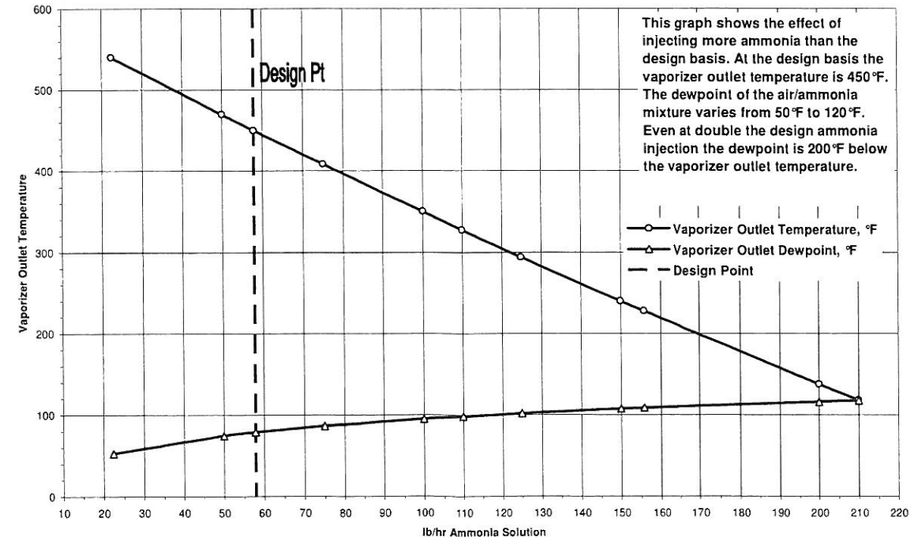
Design basis for the Ammonia injection system is:
Dry air at 0 inches water column (wc) and 0°F
Discharge pressure on fan is 45 inches wc
Fan has 50% adiabatic efficiency
Heat up air to 600°F
Inject Ammonia (also at 0°F)
Combined Ammonia and Air is 450°F – this is accomplished by setting the ammonia flow rate at 100 lb/hr and changing the air rate to accomplish this.

The heat and material balance from the above design is Prorated based on the actual required ammonia for each Source ( Crude Charge Heater, etc).

Ammonia Vaporizer
29.4 Wt% Ammonia




Ammonia Vaporizer
Dilution Air fixed at 1,932.5 Lb/Hr




This graph shows the effect of injecting more ammonia than the design basis. At the design basis the vaporizer outlet temperature is 450°F. The dewpoint of the air/ammonia mixture varies from 50°F to 120°F. Even at double the design ammonia injection the dewpoint is 200°F below the vaporizer outlet temperature.

18XC/D
AFCU Dilution Air Fan & Spare

FILE AMMONIA SKID.VSD REV 12/05/03 8:15 AM

| NO | DATE | REVISION DESCRIPTION | BY | CHK | APPD | NO | DATE |
|---|---|---|---|---|---|---|---|

REFERENCE DRAWINGS: AB-1400-40, AR-1400-20

APPROVAL

| ENGINEERING RECORD | | DATE |
|---|---|---|
| DRAWN BY | RAJ | 11/1/07 |
| DESIGNED BY | | |
| DESIGN CHECKED | | |
| APPROVED BY | | |
| APPROVED BY | | |
| WORK PKG | | |
| SCALE | | |

bp
BP CHERRY POINT

TITLE OF DRAWING: Ammonia Skid Design Basis

| PROJECT | MODULE | DISC | FAC | CONT I.D. | SEQUENCE NO | REV.NO. | OF | SHEET |
|---|---|---|---|---|---|---|---|---|
| – | | SK | 14 | XX | PFD 1 | 0 D | | 0 0 1 |

# APPENDIX C

BP BART
Ultra Low NOx Burner - Coker Charge Heater (#1 North)
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Burner Cost | $288,480 | Jacobs |
| b. Forced Draft Fan with Motor Installed Cost, if necessary | $69,581 | Jacobs |
| c. Installed Fuel Filter Skid | $57,200 | Jacobs |
| d. Duct Work Cost | $150,934 | Jacobs |
| e. SIS Instrumentation | $1,250,000 | Jacobs |
| f. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| g. Local sales tax (included in Project Contingency) | $0 | Jacobs |
| h. Freight (included in Project Contingency) | $0 | Jacobs |
| ***Primary Equipment Installed Cost*** | $1,816,196 | *Calculation* |
| B. Direct Installation Costs as Retrofit (see OAQPS, Section 1, Chapter 2, page 2-28) | | |
| a. Foundations and Supports (assumed none for LNB retrofit) | $0 | Engineering Estimate |
| b. Auxiliary Equipment (fan with motor, if necessary, & fuel filter skid) | $490,690 | Jacobs |
| c. Handling and Erection (burner installation) | $960,000 | Jacobs |
| d. Electrical, Piping, Insulation, & Painting (included in burner cost) | $0 | Jacobs |
| e. Site Preparation (assumed none for LNB retrofit) | $0 | Engineering Estimate |
| f. Off-site Facilities (addressed in burner cost) | $0 | Engineering Estimate |
| g. CEMS Installation (included in Project Contingency) | $0 | Jacobs |
| h. Engineering Design (addressed under Indirect Costs) | $0 | Jacobs |
| i. Lost Production due to extended Turnaround | $0 | Jacobs |
| j. Cost for set-up of multple units | $0 | Jacobs |
| ***Total Direct Installation Costs*** | $1,450,690 | *Calculation* |
| k. Retrofit Factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $3,266,885 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Process Contingencies (addressed in Project Contingency) | $0 | Jacobs |
| D. Other Indirect Costs | | |
| a. Preproduction Startup and Testing (included in Project Contingency) | $0 | Jacobs |
| b. Working Capital (assumed none for LNB) | $0 | Engineering Estimate |
| ***Total Indirect Costs [ICC]*** | $0 | *Calculation* |
| E. Project Contingency ([DCC + ICC]*0.4) | $1,306,754 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $4,573,640 | *Calculation* |
| F. Allowance for Funds During Construction (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5, etc. |
| G. Royalty Allowance (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| H. Inventory Capital (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| I. Initial Catalyst and Chemicals (assumed none for LNB) | $0 | Engineering Estimate |
| ***Total Capital Investment [TCI]*** | $4,573,640 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$431,719** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT ANNUAL COSTS (DAC)** | | |
| J. Labor for operations (assumed none add'l for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| K. Supervisory Labor (assumed none add'l for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| L. Maintenance Labor and Costs (0.015*TCI) | $68,605 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| M. CEMS operation | $0 | Jacobs |
| N. Utility costs (electricity for fan) | $28,271 | Jacobs |
| O. Reagent costs (assumed none for LNB) | $0 | Engineering Estimate |
| ***Total Direct Annual Costs [DAC]*** | $96,876 | *Calculation* |
| **INDIRECT ANNUAL COSTS (IDAC)** | | |
| P. Property Taxes (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| Q. Overhead (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| R. Insurance (assumed none add'l for LNB) | $0 | Jacobs |
| S. Administrative charges (assumed insignificant for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| T. Payroll & Plant Overhead (0.6*labor costs) | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 etc. |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | $0 | *Calculation* |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | **$96,876** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR LNB (TACC+TAC)*** | **$528,595** | *Calculation* |

| | | | |
|---|---|---|---|
| Baseline emissions | tons/year | 38.8 | BP Estimation for BART |
| Emissions w/new LNB | tons/year | 21.9 | Vendor Guarantee |
| Reduction from baseline | Percent | 43.5 | *Calculation* |
| Total Emissions Reduction | tons/year | 16.9 | *Calculation* |
| ***Cost per ton Controlled*** | ***$/ton*** | **$ 31,301** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quality Planning and Standards (OAQPS).

Note: The Appraise cost analysis estimated costs for the burners, burner installation, installed fan and motor, if needed, and installed fuel gas filter skid. Other items, such as sales tax, freight, engineering, and others, were assumed to be addressed en masse in the Project Contingency of 40%.

BP BART
Ultra Low NOx Burner - Coker Charge Heater (#2 South)
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Burner Cost | $288,480 | Jacobs |
| b. Forced Draft Fan with Motor Installed Cost, if necessary | $69,581 | Jacobs |
| c. Installed Fuel Filter Skid | $57,200 | Jacobs |
| d. Duct Work Cost | $150,934 | Jacobs |
| e. SIS Instrumentation | $1,250,000 | Jacobs |
| f. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| g. Local sales tax (included in Project Contingency) | $0 | Jacobs |
| h. Freight (included in Project Contingency) | $0 | Jacobs |
| ***Primary Equipment Installed Cost*** | $1,816,196 | *Calculation* |
| B. Direct Installation Costs as Retrofit (see OAQPS, Section 1, Chapter 2, page 2-28) | | |
| a. Foundations and Supports (assumed none for LNB retrofit) | $0 | Engineering Estimate |
| b. Auxiliary Equipment (fan with motor, if necessary, & fuel filter skid) | $490,690 | Jacobs |
| c. Handling and Erection (burner installation) | $960,000 | Jacobs |
| d. Electrical, Piping, Insulation, & Painting (included in burner cost) | $0 | Jacobs |
| e. Site Preparation (assumed none for LNB retrofit) | $0 | Engineering Estimate |
| f. Off-site Facilities (addressed in burner cost) | $0 | Engineering Estimate |
| g. CEMS Installation (included in Project Contingency) | $0 | Jacobs |
| h. Engineering Design (addressed under Indirect Costs) | $0 | Jacobs |
| i. Lost Production due to extended Turnaround | $0 | Jacobs |
| j. Cost for set-up of multple units | $0 | Jacobs |
| ***Total Direct Installation Costs*** | $1,450,690 | *Calculation* |
| k. Retrofit Factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $3,266,885 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Process Contingencies (addressed in Project Contingency) | $0 | Jacobs |
| D. Other Indirect Costs | | |
| a. Preproduction Startup and Testing (included in Project Contingency) | $0 | Jacobs |
| b. Working Capital (assumed none for LNB) | $0 | Engineering Estimate |
| ***Total Indirect Costs [ICC]*** | $0 | *Calculation* |
| E. Project Contingency ([DCC + ICC]*0.4) | $1,306,754 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $4,573,640 | *Calculation* |
| F. Allowance for Funds During Construction (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 and others |
| G. Royalty Allowance (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| H. Inventory Capital (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| I. Initial Catalyst and Chemicals (assumed none for LNB) | $0 | Engineering Estimate |
| ***Total Capital Investment [TCI]*** | $4,573,640 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$431,719** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT ANNUAL COSTS (DAC)** | | |
| J. Labor for operations (assumed none add'l for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| K. Supervisory Labor (assumed none add'l for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| L. Maintenance Labor and Costs (0.015*TCI) | $68,605 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| M. CEMS operation | $0 | Jacobs |
| N. Utility costs (electricity for fan) | $28,271 | Jacobs |
| O. Reagent costs (assumed none for LNB) | $0 | Engineering Estimate |
| ***Total Direct Annual Costs [DAC]*** | $96,876 | *Calculation* |
| **INDIRECT ANNUAL COSTS (IDAC)** | | |
| P. Property Taxes (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| Q. Overhead (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| R. Insurance (assumed none add'l for LNB) | $0 | Jacobs |
| S. Administrative charges (assumed insignificant for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| T. Payroll & Plant Overhead (0.6*labor costs) | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | $0 | *Calculation* |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | **$96,876** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR LNB (TACC+TAC)*** | **$528,595** | *Calculation* |
| Baseline emissions tons/year | 39.5 | BP Estimation for BART |
| Emissions w/new LNB tons/year | 22.3 | Vendor Guarantee |
| Reduction from baseline Percent | 43.5 | *Calculation* |
| Total Emissions Reduction tons/year | 17.2 | *Calculation* |
| ***Cost per ton Controlled*** ***$/ton*** | **$ 30,762** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quality Planning and Standards (OAQPS).

Note: The Appraise cost analysis estimated costs for the burners, burner installation, installed fan and motor, if needed, and installed fuel gas filter skid. Other items, such as sales tax, freight, engineering, and others, were assumed to be addressed en masse in the Project Contingency of 40%.

BP BART
Ultra Low NOx Burner - Reforming Furnace #1 (North H2 Plant)
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Burner Cost & Installation | $4,075,500 | Jacobs |
| b. Forced Draft Fan with Motor Installed Cost (included in Burner Cost) | $0 | Jacobs |
| c. Installed Fuel Filter Skid (included in Burner Cost) | $0 | Jacobs |
| d. Duct Work Cost (included in Burner Cost) | $0 | Jacobs |
| e. SIS Instrumentation | $4,009,000 | Jacobs |
| f. Instrumentation (included in Burner Cost) | $0 | Jacobs |
| g. Local sales tax (included in Burner Cost) | $0 | Jacobs |
| h. Freight (included in Burner Cost) | $0 | Jacobs |
| ***Primary Equipment Installed Cost*** | $8,084,500 | *Calculation* |
| B. Direct Installation Costs as Retrofit (see OAQPS, Section 1, Chapter 2, page 2-28) | | |
| a. Foundations and Supports (included in Burner Cost) | $0 | Engineering Estimate |
| b. Auxiliary Equipment (included in Burner Cost) | $0 | Jacobs |
| c. Handling and Erection (included in Burner Cost) | $0 | Jacobs |
| d. Electrical, Piping, Insulation, & Painting (included in Burner Cost) | $0 | Jacobs |
| e. Site Preparation (included in Burner Cost) | $0 | Engineering Estimate |
| f. Off-site Facilities (included in Burner Cost) | $0 | Engineering Estimate |
| g. CEMS Installation | $3,173,000 | Jacobs |
| h. Engineering Design (included in Burner Cost) | $0 | Jacobs |
| i. Lost Production due to extended Turnaround | $6,250,000 | Jacobs |
| j. Cost for set-up of multple units | $0 | Jacobs |
| ***Total Direct Installation Costs*** | $9,423,000 | *Calculation* |
| k. Retrofit Factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $17,507,500 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Burner Cost) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Burner Cost) | $0 | Jacobs |
| c. Contractor Fee (included in Burner Cost) | $0 | Jacobs |
| d. Process Contingencies (included in Burner Cost) | $0 | Jacobs |
| D. Other Indirect Costs | | |
| a. Preproduction Startup and Testing (included in Burner Cost) | $0 | Jacobs |
| b. Working Capital (included in Burner Cost) | $0 | Engineering Estimate |
| ***Total Indirect Costs [ICC]*** | $0 | *Calculation* |
| E. Project Contingency (included in cost estimates) | $0 | Jacobs - ROM +30% / -20% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $17,507,500 | *Calculation* |
| F. Allowance for Funds During Construction (included in Burner Cost) | $0 | Jacobs |
| G. Royalty Allowance (included in Burner Cost) | $0 | Jacobs |
| H. Inventory Capital (included in Burner Cost) | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in Burner Cost) | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | $17,507,500 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$1,652,584** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT ANNUAL COSTS (DAC)** | | |
| J. Labor for operations (assumed none add'l for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| K. Supervisory Labor (assumed none add'l for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| L. Maintenance Labor and Costs (0.015*TCI) | $168,863 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| M. CEMS operation (assumed none add'l for LNB) | $0 | Jacobs |
| N. Utility costs (assumed none add'l) | $0 | Jacobs |
| O. Reagent costs (assumed none for LNB) | $0 | Engineering Estimate |
| ***Total Direct Annual Costs [DAC]*** | $168,863 | *Calculation* |
| **INDIRECT ANNUAL COSTS (IDAC)** | | |
| P. Property Taxes (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| Q. Overhead (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| R. Insurance (assumed none add'l for LNB) | $0 | Jacobs |
| S. Administrative charges (assumed insignificant for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| T. Payroll & Plant Overhead (0.6*labor costs) | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 etc. |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | $0 | *Calculation* |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | **$168,863** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR LNB (TACC+TAC)*** | **$1,821,447** | *Calculation* |
| Baseline emissions tons/year | 132.1 | BP Estimation for BART |
| Emissions w/new LNB tons/year | 74.1 | Vendor Guarantee |
| Reduction from baseline Percent | 43.9 | *Calculation* |
| Total Emissions Reduction tons/year | 58.0 | *Calculation* |
| ***Cost per ton Controlled*** ***$/ton*** | **$ 31,430** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quality Planning and Standards (OAQPS).

Note: The Select cost analysis obtained vendor estimates for primary equipment and performed a more project-specific cost analysis for installation of ultra low NOx burners in this unit. Due to the accuracy of the project-specific cost estimate, a Contingency of between approximately 17% and 20% was utilized depending upon the unit.

BP BART
Ultra Low NOx Burner - Reforming Furnace #2 (South H2 Plant)
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Burner Cost & Installation | $4,075,500 | Jacobs |
| b. Forced Draft Fan with Motor Installed Cost (included in Burner Cost) | $0 | Jacobs |
| c. Installed Fuel Filter Skid (included in Burner Cost) | $0 | Jacobs |
| d. Duct Work Cost (included in Burner Cost) | $0 | Jacobs |
| e. SIS Instrumentation | $4,009,000 | Jacobs |
| f. Instrumentation (included in Burner Cost) | $0 | Jacobs |
| g. Local sales tax (included in Burner Cost) | $0 | Jacobs |
| h. Freight (included in Burner Cost) | $0 | Jacobs |
| ***Primary Equipment Installed Cost*** | $8,084,500 | *Calculation* |
| B. Direct Installation Costs as Retrofit (see OAQPS, Section 1, Chapter 2, page 2-28) | | |
| a. Foundations and Supports (included in Burner Cost) | $0 | Engineering Estimate |
| b. Auxiliary Equipment (included in Burner Cost) | $0 | Jacobs |
| c. Handling and Erection (included in Burner Cost) | $0 | Jacobs |
| d. Electrical, Piping, Insulation, & Painting (included in Burner Cost) | $0 | Jacobs |
| e. Site Preparation (included in Burner Cost) | $0 | Engineering Estimate |
| f. Off-site Facilities (included in Burner Cost) | $0 | Engineering Estimate |
| g. CEMS Installation | $3,173,000 | Jacobs |
| h. Engineering Design (included in Burner Cost) | $0 | Jacobs |
| i. Lost Production due to extended Turnaround | $6,250,000 | Jacobs |
| j. Cost for set-up of multple units | $0 | Jacobs |
| ***Total Direct Installation Costs*** | $9,423,000 | *Calculation* |
| k. Retrofit Factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $17,507,500 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Burner Cost) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Burner Cost) | $0 | Jacobs |
| c. Contractor Fee (included in Burner Cost) | $0 | Jacobs |
| d. Process Contingencies (included in Burner Cost) | $0 | Jacobs |
| D. Other Indirect Costs | | |
| a. Preproduction Startup and Testing (included in Burner Cost) | $0 | Jacobs |
| b. Working Capital (included in Burner Cost) | $0 | Engineering Estimate |
| ***Total Indirect Costs [ICC]*** | $0 | *Calculation* |
| E. Project Contingency (included in cost estimates) | $0 | Jacobs - ROM +30% / -20% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $17,507,500 | *Calculation* |
| F. Allowance for Funds During Construction (included in Burner Cost) | $0 | Jacobs |
| G. Royalty Allowance (included in Burner Cost) | $0 | Jacobs |
| H. Inventory Capital (included in Burner Cost) | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in Burner Cost) | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | $17,507,500 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$1,652,584** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT ANNUAL COSTS (DAC)** | | |
| J. Labor for operations (assumed none add'l for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| K. Supervisory Labor (assumed none add'l for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| L. Maintenance Labor and Costs (0.015*TCI) | $168,863 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| M. CEMS operation (assumed none add'l for LNB) | $0 | Jacobs |
| N. Utility costs (assumed none add'l) | $0 | Jacobs |
| O. Reagent costs (assumed none for LNB) | $0 | Engineering Estimate |
| ***Total Direct Annual Costs [DAC]*** | $168,863 | *Calculation* |
| **INDIRECT ANNUAL COSTS (IDAC)** | | |
| P. Property Taxes (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| Q. Overhead (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| R. Insurance (assumed none add'l for LNB) | $0 | Jacobs |
| S. Administrative charges (assumed insignificant for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| T. Payroll & Plant Overhead (0.6*labor costs) | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 etc. |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | $0 | *Calculation* |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | **$168,863** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR LNB (TACC+TAC)*** | **$1,821,447** | *Calculation* |
| Baseline emissions — tons/year | 129.5 | BP Estimation for BART |
| Emissions w/new LNB — tons/year | 72.7 | Vendor Guarantee |
| Reduction from baseline — Percent | 43.9 | *Calculation* |
| Total Emissions Reduction — tons/year | 56.8 | *Calculation* |
| ***Cost per ton Controlled*** — ***$/ton*** | **$ 32,045** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).

Note: The Select cost analysis obtained vendor estimates for primary equipment and performed a more project-specific cost analysis for installation of ultra low NOx burners in this unit. Due to the accuracy of the project-specific cost estimate, a Contingency of between approximately 17% and 20% was utilized depending upon the unit.

BP BART
Ultra Low NOx Burner - 1st Stage HC Fractionator Reboiler
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Burner Cost & Installation | $4,607,500 | Jacobs |
| b. Forced Draft Fan with Motor Installed Cost (included in Burner Cost) | $0 | Jacobs |
| c. Installed Fuel Filter Skid (included in Burner Cost) | $0 | Jacobs |
| d. Duct Work Cost (included in Burner Cost) | $0 | Jacobs |
| e. SIS Instrumentation | $1,016,500 | Jacobs |
| f. Instrumentation (included in Burner Cost) | $0 | Jacobs |
| g. Local sales tax (included in Burner Cost) | $0 | Jacobs |
| h. Freight (included in Burner Cost) | $0 | Jacobs |
| ***Primary Equipment Installed Cost*** | $5,624,000 | *Calculation* |
| B. Direct Installation Costs as Retrofit (see OAQPS, Section 1, Chapter 2, page 2-28) | | |
| a. Foundations and Supports (included in Burner Cost) | $0 | Engineering Estimate |
| b. Auxiliary Equipment (included in Burner Cost) | $0 | Jacobs |
| c. Handling and Erection (included in Burner Cost) | $0 | Jacobs |
| d. Electrical, Piping, Insulation, & Painting (included in Burner Cost) | $0 | Jacobs |
| e. Site Preparation (included in Burner Cost) | $0 | Engineering Estimate |
| f. Off-site Facilities (included in Burner Cost) | $0 | Engineering Estimate |
| g. CEMS Installation | $2,717,000 | Jacobs |
| h. Engineering Design (included in Burner Cost) | $0 | Jacobs |
| i. Lost Production due to extended Turnaround | $0 | Jacobs |
| j. Cost for set-up of multple units | $0 | Jacobs |
| ***Total Direct Installation Costs*** | $2,717,000 | *Calculation* |
| k. Retrofit Factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $8,341,000 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Burner Cost) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Burner Cost) | $0 | Jacobs |
| c. Contractor Fee (included in Burner Cost) | $0 | Jacobs |
| d. Process Contingencies (included in Burner Cost) | $0 | Jacobs |
| D. Other Indirect Costs | | |
| a. Preproduction Startup and Testing (included in Burner Cost) | $0 | Jacobs |
| b. Working Capital (included in Burner Cost) | $0 | Engineering Estimate |
| ***Total Indirect Costs [ICC]*** | $0 | *Calculation* |
| E. Project Contingency (included in cost estimates) | $0 | Jacobs - ROM +30% / -20% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $8,341,000 | *Calculation* |
| F. Allowance for Funds During Construction (included in Burner Cost) | $0 | Jacobs |
| G. Royalty Allowance (included in Burner Cost) | $0 | Jacobs |
| H. Inventory Capital (included in Burner Cost) | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in Burner Cost) | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | $8,341,000 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$787,331** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT ANNUAL COSTS (DAC)** | | |
| J. Labor for operations (assumed none add'l for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| K. Supervisory Labor (assumed none add'l for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| L. Maintenance Labor and Costs (0.015*TCI) | $125,115 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| M. CEMS operation (assumed none add'l for LNB) | $0 | Jacobs |
| N. Utility costs (assumed none add'l) | $0 | Jacobs |
| O. Reagent costs (assumed none for LNB) | $0 | Engineering Estimate |
| ***Total Direct Annual Costs [DAC]*** | $125,115 | *Calculation* |
| **INDIRECT ANNUAL COSTS (IDAC)** | | |
| P. Property Taxes (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| Q. Overhead (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| R. Insurance (assumed none add'l for LNB) | $0 | Jacobs |
| S. Administrative charges (assumed insignificant for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| T. Payroll & Plant Overhead (0.6*labor costs) | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 etc. |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | $0 | *Calculation* |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | **$125,115** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR LNB (TACC+TAC)*** | **$912,446** | *Calculation* |
| Baseline emissions tons/year | 113.6 | BP Estimation for BART |
| Emissions w/new LNB tons/year | 37.9 | Vendor Guarantee |
| Reduction from baseline Percent | 66.7 | *Calculation* |
| Total Emissions Reduction tons/year | 75.8 | *Calculation* |
| ***Cost per ton Controlled*** ***$/ton*** | **$ 12,044** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quality Planning and Standards (OAQPS).

Note: The Select cost analysis obtained vendor estimates for primary equipment and performed a more project-specific cost analysis for installation of ultra low NOx burners in this unit. Due to the accuracy of the project-specific cost estimate, a Contingency of between approximately 17% and 20% was utilized depending upon the unit.

BP BART
Ultra Low NOx Burner - 2nd Stage HC Fractionator Reboiler
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Burner Cost | $109,000 | Jacobs |
| b. Forced Draft Fan with Motor Installed Cost, if necessary | $0 | Jacobs |
| c. Installed Fuel Filter Skid | $57,200 | Jacobs |
| d. Duct Work Cost (included in Project Contingency) | $0 | Jacobs |
| e. SIS Instrumentation | $1,250,000 | Jacobs |
| f. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| g. Local sales tax (included in Project Contingency) | $0 | Jacobs |
| h. Freight (included in Project Contingency) | $0 | Jacobs |
| ***Primary Equipment Installed Cost*** | $1,416,200 | *Calculation* |
| B. Direct Installation Costs as Retrofit (see OAQPS, Section 1, Chapter 2, page 2-28) | | |
| a. Foundations and Supports (assumed none for LNB retrofit) | $0 | Engineering Estimate |
| b. Auxiliary Equipment (fan with motor, if necessary, & fuel filter skid) | $228,800 | Jacobs |
| c. Handling and Erection (burner installation) | $160,000 | Jacobs |
| d. Electrical, Piping, Insulation, & Painting (included in burner cost) | $0 | Jacobs |
| e. Site Preparation (assumed none for LNB retrofit) | $0 | Engineering Estimate |
| f. Off-site Facilities (addressed in burner cost) | $0 | Engineering Estimate |
| g. CEMS Installation (included in Project Contingency) | $0 | Jacobs |
| h. Engineering Design (addressed under Indirect Costs) | $0 | Jacobs |
| i. Lost Production due to extended Turnaround | $0 | Jacobs |
| j. Cost for set-up of multple units | $0 | Jacobs |
| ***Total Direct Installation Costs*** | $388,800 | *Calculation* |
| k. Retrofit Factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $1,805,000 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Process Contingencies (addressed in Project Contingency) | $0 | Jacobs |
| D. Other Indirect Costs | | |
| a. Preproduction Startup and Testing (included in Project Contingency) | $0 | Jacobs |
| b. Working Capital (assumed none for LNB) | $0 | Engineering Estimate |
| ***Total Indirect Costs [ICC]*** | $0 | *Calculation* |
| E. Project Contingency ([DCC + ICC]*0.4) | $722,000 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $2,527,000 | *Calculation* |
| F. Allowance for Funds During Construction (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5, etc. |
| G. Royalty Allowance (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| H. Inventory Capital (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| I. Initial Catalyst and Chemicals (assumed none for LNB) | $0 | Engineering Estimate |
| ***Total Capital Investment [TCI]*** | $2,527,000 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$238,531** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT ANNUAL COSTS (DAC)** | | |
| J. Labor for operations (assumed none add'l for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| K. Supervisory Labor (assumed none add'l for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| L. Maintenance Labor and Costs (0.015*TCI) | $37,905 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| M. CEMS operation | $0 | Jacobs |
| N. Utility costs (electricity for fan) | $0 | Jacobs |
| O. Reagent costs (assumed none for LNB) | $0 | Engineering Estimate |
| ***Total Direct Annual Costs [DAC]*** | $37,905 | *Calculation* |
| **INDIRECT ANNUAL COSTS (IDAC)** | | |
| P. Property Taxes (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| Q. Overhead (assumed none for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| R. Insurance (assumed none add'l for LNB) | $0 | Jacobs |
| S. Administrative charges (assumed insignificant for LNB) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| T. Payroll & Plant Overhead (0.6*labor costs) | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 etc. |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | $0 | *Calculation* |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | **$37,905** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR LNB (TACC+TAC)*** | **$276,436** | *Calculation* |

| | | | |
|---|---|---|---|
| Baseline emissions | tons/year | 36.1 | BP Estimation for BART |
| Emissions w/new LNB | tons/year | 28.5 | Vendor Guarantee |
| Reduction from baseline | Percent | 21.1 | *Calculation* |
| Total Emissions Reduction | tons/year | 7.6 | *Calculation* |
| ***Cost per ton Controlled*** | ***$/ton*** | **$ 36,395** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).

Note: The Appraise cost analysis estimated costs for the burners, burner installation, installed fan and motor, if needed, and installed fuel gas filter skid. Other items, such as sales tax, freight, engineering, and others, were assumed to be addressed

BP BART
SCR Cost Effectiveness Calculation - Crude Charge Heater
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Equipment Design Considerations | | |
| a. SCR Cost (including adjustment for SCR reactor height and bypass installation) | $53,494,500 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | $3,601,776 | Jacobs |
| c. Initial Charge of Catalyst (included in SCR Cost) | $0 | Jacobs |
| d. ID Fan Cost (included in SCR Cost) | $0 | Jacobs |
| e. ID Fan Motor Cost (included in SCR Cost) | $0 | Jacobs |
| f. Convection Section Cost (included in SCR Cost) | $0 | Jacobs |
| g. Duct Work Cost (included in SCR Cost) | $0 | Jacobs |
| h. Plot Plant Installation Factor (included in SCR Cost) | 1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $57,096,276 | *Calculation* |
| i. SIS Instrumentation (included in SCR Cost) | $0 | Jacobs |
| j. CEMS Installation (included in SCR Cost) | $0 | Jacobs |
| k. Local Sales tax (included in SCR Cost) | $0 | Jacobs |
| l. Freight (included in SCR Cost) | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $57,096,276 | |
| **INDIRECT COSTS** | | |
| B. Indirect Installation | | |
| a. General Facilities (included in SCR Cost) | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in SCR Cost) | $0 | Jacobs |
| c. Process Contingency (included in SCR Cost) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | *Calculation* |
| C. Project Contingency (included in SCR Cost) | $0 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $57,096,276 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in SCR Cost) | $0 | Jacobs |
| H. Inventory Capital (included in SCR Cost) | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in SCR Cost) | $0 | Jacobs |
| J. Cost for set-up of multple units | $0 | Jacobs |
| K. Lost Production due to extended turnaround | $84,000,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | $141,096,276 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$13,318,490** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT ANNUAL COSTS (DAC)** | | |
| M. Labor for operations (assumed none add'l for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| N. Supervisory Labor (assumed none add'l for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Maintenance Labor and Costs (0.015*TCI) | $856,444 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. CEMS operation (assumed none add'l for SCR) | $0 | Jacobs |
| Q. Consumables - Reagent | $56,712 | Jacobs |
| R. Consumables - Catalyst (annualized over 5 years @ 7% interest) | $158,758 | Jacobs |
| S. Utility costs - fan & ammonia vaporization (electricity) | $222,431 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | $1,294,345 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | |
| T. Property Taxes (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| U. Overhead (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Insurance (assumed insignificant for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Administrative charges (assumed insignificant for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Payroll Overhead (0.6*labor costs) | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Y. Plant Overhead (assumed negligible for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | **$1,294,345** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | **$14,612,836** | *Calculation* |

| | | | |
|---|---|---|---|
| Uncontrolled emissions | tons/year | 480.7 | BP Estimation for BART |
| Emissions w/SCR | tons/year | 24.0 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from baseline | Percent | 95.0 | *Calculation* |
| Total Emissions Reduction | tons/year | 456.6 | *Calculation* |
| ***Cost per ton Controlled*** | ***$/ton*** | **$ 32,001** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).
Section 4.2 Chapter 2: Selective Catalytic Reduction (October 2000)

Note: The Select cost analysis obtained vendor estimates for primary equipment and performed a more project-specific cost analysis for installation of SCR on this unit. Due to the accuracy of the project-specific cost estimate, a Contingency of between approximately 17% and 20% was utilized depending upon the unit.

BP BART
SCR Cost Effectiveness Calculation - South Vacuum Heater
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Equipment Design Considerations | | |
| a. Reactor Cost (including adjustment for SCR reactor height and bypass installation) | $2,209,966 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | $1,228,766 | Jacobs |
| c. Initial Charge of Catalyst | $176,334 | Jacobs |
| d. ID Fan Cost | $836,841 | Jacobs |
| e. ID Fan Motor Cost | $221,794 | Jacobs |
| f. Convection Section Cost | $1,064,662 | Jacobs |
| g. Duct Work Cost | $1,284,296 | Jacobs |
| h. Plot Plant Installation Factor (addressed ease of installation - new or retrofit) | 1.1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $7,724,923 | *Calculation* |
| i. SIS Instrumentation | $1,250,000 | Jacobs |
| j. CEMS Installation (included in SCR Cost) | $0 | Jacobs |
| k. Local Sales tax (included in Project Contingency) | $0 | Jacobs |
| l. Freight (included in SCR cost) | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $8,974,923 | |
| **INDIRECT COSTS** | | |
| B. Indirect Installation | | |
| a. General Facilities (included in Project Contingency) | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in Project Contingency) | $0 | Jacobs |
| c. Process Contingency (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | *Calculation* |
| C. Project Contingency ([DCC + ICC]*0.40) | $3,589,969 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $12,564,893 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in Project Contingency) | $0 | Jacobs |
| H. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in SCR Cost) | $0 | Jacobs |
| J. Cost for set-up of multple units | $0 | Jacobs |
| K. Lost Production due to extended turnaround | $8,000,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | $20,564,893 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$1,941,180** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT ANNUAL COSTS (DAC)** | | |
| M. Labor for operations (assumed none add'l for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| N. Supervisory Labor (assumed none add'l for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Maintenance Labor and Costs (0.015*TCI) | $188,473 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. CEMS operation (assumed none add'l for SCR) | $0 | Jacobs |
| Q. Consumables - Reagent | $4,656 | Jacobs |
| R. Consumables - Catalyst (annualized over 5 years @ 7% interest) | $43,006 | Jacobs |
| S. Utility costs - fan & ammonia vaporization (electricity) | $50,634 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | $286,770 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | |
| T. Property Taxes (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| U. Overhead (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Insurance (assumed insignificant for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Administrative charges (assumed insignificant for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Payroll Overhead (0.6*labor costs) | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Y. Plant Overhead (assumed negligible for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | **$286,770** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | **$2,227,950** | *Calculation* |
| Uncontrolled emissions tons/year | 31.8 | BP Estimation for BART |
| Emissions w/SCR tons/year | 4.9 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from baseline Percent | 84.7 | *Calculation* |
| Total Emissions Reduction tons/year | 27.0 | *Calculation* |
| ***Cost per ton Controlled*** ***$/ton*** | **$ 82,643** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quality Planning and Standards (OAQPS).
Section 4.2 Chapter 2: Selective Catalytic Reduction (October 2000)

Note: The Appraise cost analysis estimated costs for the reactor, duct work, ammonia delivery system, catalyst, and ID fan. Other items, such as sales tax, freight, engineering, and others, were assumed to be addressed en masse in the Project Contingency of 40%.

BP BART
SCR Cost Effectiveness Calculation - Naphtha HDS Charge Heater
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Equipment Design Considerations | | |
| a. Reactor Cost (including adjustment for SCR reactor height and bypass installation) | $1,444,230 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | $1,234,132 | Jacobs |
| c. Initial Charge of Catalyst | $114,618 | Jacobs |
| d. ID Fan Cost | $726,150 | Jacobs |
| e. ID Fan Motor Cost | $140,727 | Jacobs |
| f. Convection Section Cost | $883,911 | Jacobs |
| g. Duct Work Cost | $1,141,086 | Jacobs |
| h. Plot Plant Installation Factor (addressed ease of installation - new or retrofit) | 1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $5,684,855 | *Calculation* |
| i. SIS Instrumentation | $1,250,000 | Jacobs |
| j. CEMS Installation (included in SCR Cost) | $0 | Jacobs |
| k. Local Sales tax (included in Project Contingency) | $0 | Jacobs |
| l. Freight (included in SCR cost) | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $6,934,855 | |
| **INDIRECT COSTS** | | |
| B. Indirect Installation | | |
| a. General Facilities (included in Project Contingency) | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in Project Contingency) | $0 | Jacobs |
| c. Process Contingency (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | *Calculation* |
| C. Project Contingency ([DCC + ICC]*0.40) | $2,773,942 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $9,708,797 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in Project Contingency) | $0 | Jacobs |
| H. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in SCR Cost) | $0 | Jacobs |
| J. Cost for set-up of multple units | $0 | Jacobs |
| K. Lost Production due to extended turnaround | $2,500,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | $12,208,797 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$1,152,424** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT ANNUAL COSTS (DAC)** | | |
| M. Labor for operations (assumed none add'l for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| N. Supervisory Labor (assumed none add'l for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Maintenance Labor and Costs (0.015*TCI) | $145,632 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. CEMS operation (assumed none add'l for SCR) | $0 | Jacobs |
| Q. Consumables - Reagent | $5,525 | Jacobs |
| R. Consumables - Catalyst (annualized over 5 years @ 7% interest) | $27,954 | Jacobs |
| S. Utility costs - fan & ammonia vaporization (electricity) | $43,070 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | $222,181 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | |
| T. Property Taxes (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| U. Overhead (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Insurance (assumed insignificant for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Administrative charges (assumed insignificant for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Payroll Overhead (0.6*labor costs) | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Y. Plant Overhead (assumed negligible for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | **$222,181** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | **$1,374,605** | *Calculation* |
| Uncontrolled emissions tons/year | 45.5 | BP Estimation for BART |
| Emissions w/SCR tons/year | 2.8 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from baseline Percent | 93.9 | *Calculation* |
| Total Emissions Reduction tons/year | 42.7 | *Calculation* |
| ***Cost per ton Controlled*** ***$/ton*** | **$ 32,175** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quality Planning and Standards (OAQPS).
Section 4.2 Chapter 2: Selective Catalytic Reduction (October 2000)

Note: The Appraise cost analysis estimated costs for the reactor, duct work, ammonia delivery system, catalyst, and ID fan. Other items, such as sales tax, freight, engineering, and others, were assumed to be addressed en masse in the Project Contingency of 40%.

BP BART
SCR Cost Effectiveness Calculation - Naphtha HDS Stripper Reboiler
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Equipment Design Considerations | | | |
| a. Reactor Cost (including adjustment for SCR reactor height and bypass installation) | | $1,073,880 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | | $1,220,866 | Jacobs |
| c. Initial Charge of Catalyst | | $70,070 | Jacobs |
| d. ID Fan Cost | | $496,497 | Jacobs |
| e. ID Fan Motor Cost | | $96,220 | Jacobs |
| f. Convection Section Cost | | $0 | Jacobs |
| g. Duct Work Cost | | $831,240 | Jacobs |
| h. Plot Plant Installation Factor (addressed ease of installation - new or retrofit) | | 1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $3,788,774 | *Calculation* |
| i. SIS Instrumentation | | $1,250,000 | Jacobs |
| j. CEMS Installation (included in SCR Cost) | | $0 | Jacobs |
| k. Local Sales tax (included in Project Contingency) | | $0 | Jacobs |
| l. Freight (included in SCR cost) | | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $5,038,774 | |
| **INDIRECT COSTS** | | | |
| B. Indirect Installation | | | |
| a. General Facilities (included in Project Contingency) | | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in Project Contingency) | | $0 | Jacobs |
| c. Process Contingency (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| C. Project Contingency ([DCC + ICC]*0.40) | | $2,015,509 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $7,054,283 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in Project Contingency) | | $0 | Jacobs |
| H. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in SCR Cost) | | $0 | Jacobs |
| J. Cost for set-up of multple units | | $0 | Jacobs |
| K. Lost Production due to extended turnaround | | $2,500,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $9,554,283 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$901,857** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT ANNUAL COSTS (DAC)** | | | |
| M. Labor for operations (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| N. Supervisory Labor (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Maintenance Labor and Costs (0.015*TCI) | | $105,814 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. CEMS operation (assumed none add'l for SCR) | | $0 | Jacobs |
| Q. Consumables - Reagent | | $3,378 | Jacobs |
| R. Consumables - Catalyst (annualized over 5 years @ 7% interest) | | $17,090 | Jacobs |
| S. Utility costs - fan & ammonia vaporization (electricity) | | $23,654 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | | $149,935 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | | |
| T. Property Taxes (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| U. Overhead (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Insurance (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Administrative charges (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Payroll Overhead (0.6*labor costs) | | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Y. Plant Overhead (assumed negligible for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | | **$149,935** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | | **$1,051,792** | *Calculation* |
| Uncontrolled emissions | tons/year | 27.5 | BP Estimation for BART |
| Emissions w/SCR | tons/year | 1.7 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from baseline | Percent | 93.9 | *Calculation* |
| Total Emissions Reduction | tons/year | 25.8 | *Calculation* |
| ***Cost per ton Controlled*** | ***$/ton*** | **$ 40,711** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).
Section 4.2 Chapter 2: Selective Catalytic Reduction (October 2000)

Note: The Appraise cost analysis estimated costs for the reactor, duct work, ammonia delivery system, catalyst, and ID fan. Other items, such as sales tax, freight, engineering, and others, were assumed to be addressed en masse in the Project Contingency of 40%.

BP BART
SCR Cost Effectiveness Calculation - #1 Reformer Heaters
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Equipment Design Considerations | | |
| a. SCR Cost (including adjustment for SCR reactor height and bypass installation) | $53,675,000 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | $3,519,232 | Jacobs |
| c. Initial Charge of Catalyst (included in SCR Cost) | $0 | Jacobs |
| d. ID Fan Cost (included in SCR Cost) | $0 | Jacobs |
| e. ID Fan Motor Cost (included in SCR Cost) | $0 | Jacobs |
| f. Convection Section Cost (included in SCR Cost) | $0 | Jacobs |
| g. Duct Work Cost (included in SCR Cost) | $0 | Jacobs |
| h. Plot Plant Installation Factor (included in SCR Cost) | 1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $57,194,232 | *Calculation* |
| i. SIS Instrumentation (included in SCR Cost) | $0 | Jacobs |
| j. CEMS Installation (included in SCR Cost) | $0 | Jacobs |
| k. Local Sales tax (included in Project Contingency) | $0 | Jacobs |
| l. Freight (included in SCR cost) | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $57,194,232 | |
| **INDIRECT COSTS** | | |
| B. Indirect Installation | | |
| a. General Facilities (included in SCR Cost) | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in SCR Cost) | $0 | Jacobs |
| c. Process Contingency (included in SCR Cost) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | *Calculation* |
| C. Project Contingency (included in SCR Cost) | $0 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $57,194,232 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in SCR Cost) | $0 | Jacobs |
| H. Inventory Capital (included in SCR Cost) | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in SCR Cost) | $0 | Jacobs |
| J. Cost for set-up of multple units | $0 | Jacobs |
| K. Lost Production due to extended turnaround | $9,600,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | $66,794,232 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$6,304,903** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT ANNUAL COSTS (DAC)** | | |
| M. Labor for operations (assumed none add'l for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| N. Supervisory Labor (assumed none add'l for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Maintenance Labor and Costs (0.015*TCI) | $857,913 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. CEMS operation (assumed none add'l for SCR) | $0 | Jacobs |
| Q. Consumables - Reagent | $55,412 | Jacobs |
| R. Consumables - Catalyst (annualized over 5 years @ 7% interest) | $163,392 | Jacobs |
| S. Utility costs - fan & ammonia vaporization (electricity) | $278,095 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | $1,354,813 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | |
| T. Property Taxes (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| U. Overhead (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Insurance (assumed insignificant for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Administrative charges (assumed insignificant for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Payroll Overhead (0.6*labor costs) | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Y. Plant Overhead (assumed negligible for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | **$1,354,813** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | **$7,659,716** | *Calculation* |
| Uncontrolled emissions tons/year | 466.1 | BP Estimation for BART |
| Emissions w/SCR tons/year | 23.3 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from baseline Percent | 95.0 | *Calculation* |
| Total Emissions Reduction tons/year | 442.8 | *Calculation* |
| ***Cost per ton Controlled*** ***$/ton*** | **$ 17,299** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).
Section 4.2 Chapter 2: Selective Catalytic Reduction (October 2000)

Note: The Select cost analysis obtained vendor estimates for primary equipment and performed a more project-specific cost analysis for installation of SCR on this unit. Due to the accuracy of the project-specific cost estimate, a Contingency of between approximately 17% and 20% was utilized depending upon the unit.

BP BART
SCR Cost Effectiveness Calculation - Coker Charge Heater (#1 North)
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Equipment Design Considerations | | | |
| a. Reactor Cost (including adjustment for SCR reactor height and bypass installation) | | $2,208,974 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | | $1,240,105 | Jacobs |
| c. Initial Charge of Catalyst | | $259,846 | Jacobs |
| d. ID Fan Cost | | $838,517 | Jacobs |
| e. ID Fan Motor Cost | | $162,503 | Jacobs |
| f. Convection Section Cost | | $0 | Jacobs |
| g. Duct Work Cost | | $1,286,440 | Jacobs |
| h. Plot Plant Installation Factor (addressed ease of installation - new or retrofit) | | 1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $5,996,385 | *Calculation* |
| i. SIS Instrumentation | | $1,250,000 | Jacobs |
| j. CEMS Installation (included in SCR Cost) | | $0 | Jacobs |
| k. Local Sales tax (included in Project Contingency) | | $0 | Jacobs |
| l. Freight (included in SCR cost) | | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $7,246,385 | |
| **INDIRECT COSTS** | | | |
| B. Indirect Installation | | | |
| a. General Facilities (included in Project Contingency) | | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in Project Contingency) | | $0 | Jacobs |
| c. Process Contingency (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| C. Project Contingency ([DCC + ICC]*0.40) | | $2,898,554 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $10,144,939 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in Project Contingency) | | $0 | Jacobs |
| H. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in SCR Cost) | | $0 | Jacobs |
| J. Cost for set-up of multple units | | $0 | Jacobs |
| K. Lost Production due to extended turnaround | | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $10,144,939 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$957,610** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT ANNUAL COSTS (DAC)** | | | |
| M. Labor for operations (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| N. Supervisory Labor (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Maintenance Labor and Costs (0.015*TCI) | | $152,174 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. CEMS operation (assumed none add'l for SCR) | | $0 | Jacobs |
| Q. Consumables - Reagent | | $6,492 | Jacobs |
| R. Consumables - Catalyst (annualized over 5 years @ 7% interest) | | $63,374 | Jacobs |
| S. Utility costs - fan & ammonia vaporization (electricity) | | $53,791 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | | $275,831 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | | |
| T. Property Taxes (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| U. Overhead (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Insurance (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Administrative charges (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Payroll Overhead (0.6*labor costs) | | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Y. Plant Overhead (assumed negligible for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | | **$275,831** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | | **$1,233,442** | *Calculation* |
| Uncontrolled emissions | tons/year | 38.8 | BP Estimation for BART |
| Emissions w/SCR | tons/year | 3.7 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from baseline | Percent | 90.4 | *Calculation* |
| Total Emissions Reduction | tons/year | 35.0 | *Calculation* |
| ***Cost per ton Controlled*** | ***$/ton*** | **$ 35,202** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).
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Note: The Appraise cost analysis estimated costs for the reactor, duct work, ammonia delivery system, catalyst, and ID fan. Other items, such as sales tax, freight, engineering, and others, were assumed to be addressed en masse in the Project Contingency of 40%.

BP BART
SCR Cost Effectiveness Calculation - Coker Charge Heater (#2 South)
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Equipment Design Considerations | | |
| a. Reactor Cost (including adjustment for SCR reactor height and bypass installation) | $2,208,974 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | $1,240,105 | Jacobs |
| c. Initial Charge of Catalyst | $259,846 | Jacobs |
| d. ID Fan Cost | $838,517 | Jacobs |
| e. ID Fan Motor Cost | $162,503 | Jacobs |
| f. Convection Section Cost | $0 | Jacobs |
| g. Duct Work Cost | $1,286,440 | Jacobs |
| h. Plot Plant Installation Factor (addressed ease of installation - new or retrofit) | 1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $5,996,385 | *Calculation* |
| i. SIS Instrumentation | $1,250,000 | Jacobs |
| j. CEMS Installation (included in SCR Cost) | $0 | Jacobs |
| k. Local Sales tax (included in Project Contingency) | $0 | Jacobs |
| l. Freight (included in SCR cost) | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $7,246,385 | |
| **INDIRECT COSTS** | | |
| B. Indirect Installation | | |
| a. General Facilities (included in Project Contingency) | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in Project Contingency) | $0 | Jacobs |
| c. Process Contingency (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | *Calculation* |
| C. Project Contingency ([DCC + ICC]*0.40) | $2,898,554 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $10,144,939 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in Project Contingency) | $0 | Jacobs |
| H. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in SCR Cost) | $0 | Jacobs |
| J. Cost for set-up of multple units | $0 | Jacobs |
| K. Lost Production due to extended turnaround | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | $10,144,939 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$957,610** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT ANNUAL COSTS (DAC)** | | |
| M. Labor for operations (assumed none add'l for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| N. Supervisory Labor (assumed none add'l for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Maintenance Labor and Costs (0.015*TCI) | $152,174 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. CEMS operation (assumed none add'l for SCR) | $0 | Jacobs |
| Q. Consumables - Reagent | $6,492 | Jacobs |
| R. Consumables - Catalyst (annualized over 5 years @ 7% interest) | $63,374 | Jacobs |
| S. Utility costs - fan & ammonia vaporization (electricity) | $53,791 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | $275,831 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | |
| T. Property Taxes (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| U. Overhead (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Insurance (assumed insignificant for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Administrative charges (assumed insignificant for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Payroll Overhead (0.6*labor costs) | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Y. Plant Overhead (assumed negligible for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | **$275,831** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | **$1,233,442** | *Calculation* |

| | | | |
|---|---|---|---|
| Uncontrolled emissions | tons/year | 39.5 | BP Estimation for BART |
| Emissions w/SCR | tons/year | 3.8 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from baseline | Percent | 90.4 | *Calculation* |
| Total Emissions Reduction | tons/year | 35.7 | *Calculation* |
| ***Cost per ton Controlled*** | ***$/ton*** | **$ 34,597** | *Calculation* |

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Section 4.2 Chapter 2: Selective Catalytic Reduction (October 2000)

Note: The Appraise cost analysis estimated costs for the reactor, duct work, ammonia delivery system, catalyst, and ID fan. Other items, such as sales tax, freight, engineering, and others, were assumed to be addressed en masse in the Project Contingency of 40%.

BP BART
SCR Cost Effectiveness Calculation - Diesel HDS Charge Heater
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Equipment Design Considerations | | |
| a. Reactor Cost (including adjustment for SCR reactor height and bypass installation) | $884,348 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | $1,205,510 | Jacobs |
| c. Initial Charge of Catalyst | $41,054 | Jacobs |
| d. ID Fan Cost | $379,148 | Jacobs |
| e. ID Fan Motor Cost | $73,478 | Jacobs |
| f. Convection Section Cost | $0 | Jacobs |
| g. Duct Work Cost | $663,952 | Jacobs |
| h. Plot Plant Installation Factor (addressed ease of installation - new or retrofit) | 1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $3,247,491 | *Calculation* |
| i. SIS Instrumentation | $1,250,000 | Jacobs |
| j. CEMS Installation (included in SCR Cost) | $0 | Jacobs |
| k. Local Sales tax (included in Project Contingency) | $0 | Jacobs |
| l. Freight (included in SCR cost) | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $4,497,491 | |
| **INDIRECT COSTS** | | |
| B. Indirect Installation | | |
| a. General Facilities (included in Project Contingency) | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in Project Contingency) | $0 | Jacobs |
| c. Process Contingency (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | *Calculation* |
| C. Project Contingency ([DCC + ICC]*0.40) | $1,798,996 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $6,296,487 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in Project Contingency) | $0 | Jacobs |
| H. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in SCR Cost) | $0 | Jacobs |
| J. Cost for set-up of multple units | $0 | Jacobs |
| K. Lost Production due to extended turnaround | $3,500,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | $9,796,487 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$924,719** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT ANNUAL COSTS (DAC)** | | |
| M. Labor for operations (assumed none add'l for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| N. Supervisory Labor (assumed none add'l for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Maintenance Labor and Costs (0.015*TCI) | $94,447 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. CEMS operation (assumed none add'l for SCR) | $0 | Jacobs |
| Q. Consumables - Reagent | $892 | Jacobs |
| R. Consumables - Catalyst (annualized over 5 years @ 7% interest) | $10,013 | Jacobs |
| S. Utility costs - fan & ammonia vaporization (electricity) | $12,829 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | $118,181 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | |
| T. Property Taxes (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| U. Overhead (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Insurance (assumed insignificant for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Administrative charges (assumed insignificant for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Payroll Overhead (0.6*labor costs) | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Y. Plant Overhead (assumed negligible for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | **$118,181** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | **$1,042,900** | *Calculation* |
| Uncontrolled emissions tons/year | 4.6 | BP Estimation for BART |
| Emissions w/SCR tons/year | 0.9 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from baseline Percent | 80.7 | *Calculation* |
| Total Emissions Reduction tons/year | 3.7 | *Calculation* |
| ***Cost per ton Controlled*** ***$/ton*** | **$ 282,388** | *Calculation* |

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Section 4.2 Chapter 2: Selective Catalytic Reduction (October 2000)

Note: The Appraise cost analysis estimated costs for the reactor, duct work, ammonia delivery system, catalyst, and ID fan. Other items, such as sales tax, freight, engineering, and others, were assumed to be addressed en masse in the Project Contingency of 40%.

BP BART
SCR Cost Effectiveness Calculation - Diesel HDS Stabilizer Reboiler
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Equipment Design Considerations | | |
| a. Reactor Cost (including adjustment for SCR reactor height and bypass installation) | $1,031,893 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | $1,206,364 | Jacobs |
| c. Initial Charge of Catalyst | $44,248 | Jacobs |
| d. ID Fan Cost | $481,367 | Jacobs |
| e. ID Fan Motor Cost | $93,288 | Jacobs |
| f. Convection Section Cost | $0 | Jacobs |
| g. Duct Work Cost | $810,077 | Jacobs |
| h. Plot Plant Installation Factor (addressed ease of installation - new or retrofit) | 1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $3,667,237 | *Calculation* |
| i. SIS Instrumentation | $1,250,000 | Jacobs |
| j. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| k. Local Sales tax (included in Project Contingency) | $0 | Jacobs |
| l. Freight (included in Project Contingency) | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $4,917,237 | |
| **INDIRECT COSTS** | | |
| B. Indirect Installation | | |
| a. General Facilities (included in Project Contingency) | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in Project Contingency) | $0 | Jacobs |
| c. Process Contingency (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | *Calculation* |
| C. Project Contingency ([DCC + ICC]*0.40) | $1,966,895 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $6,884,131 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in Project Contingency) | $0 | Jacobs |
| H. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in SCR Cost) | $0 | Jacobs |
| J. Cost for set-up of multple units | $0 | Jacobs |
| K. Lost Production due to extended turnaround | $3,500,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | $10,384,131 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$980,189** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT ANNUAL COSTS (DAC)** | | |
| M. Labor for operations (assumed none add'l for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| N. Supervisory Labor (assumed none add'l for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Maintenance Labor and Costs (0.015*TCI) | $103,262 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. CEMS operation (assumed none add'l for SCR) | $0 | Jacobs |
| Q. Consumables - Reagent | $1,030 | Jacobs |
| R. Consumables - Catalyst (annualized over 5 years @ 7% interest) | $10,792 | Jacobs |
| S. Utility costs - fan & ammonia vaporization (electricity) | $18,564 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | $133,648 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | |
| T. Property Taxes (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| U. Overhead (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Insurance (assumed insignificant for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Administrative charges (assumed insignificant for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Payroll Overhead (0.6*labor costs) | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Y. Plant Overhead (assumed negligible for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | **$133,648** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | **$1,113,836** | *Calculation* |
| Uncontrolled emissions tons/year | 6.9 | BP Estimation for BART |
| Emissions w/SCR tons/year | 1.5 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from baseline Percent | 78.6 | *Calculation* |
| Total Emissions Reduction tons/year | 5.4 | *Calculation* |
| ***Cost per ton Controlled $/ton*** | **$ 206,592** | *Calculation* |

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Section 4.2 Chapter 2: Selective Catalytic Reduction (October 2000)

Note: The Appraise cost analysis estimated costs for the reactor, duct work, ammonia delivery system, catalyst, and ID fan. Other items, such as sales tax, freight, engineering, and others, were assumed to be addressed en masse in the Project Contingency of 40%.

BP BART

SCR Cost Effectiveness Calculation - #1 Reforming Furnace (North H2 Plant)

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Equipment Design Considerations | | | |
| a. SCR Cost (including adjustment for SCR reactor height and bypass installation) | | $23,634,480 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | | $1,018,927 | Jacobs |
| c. Initial Charge of Catalyst (included in SCR Cost) | | $115,520 | Jacobs |
| d. ID Fan Cost (included in SCR Cost) | | $0 | Jacobs |
| e. ID Fan Motor Cost (included in SCR Cost) | | $0 | Jacobs |
| f. Convection Section Cost (included in SCR Cost) | | $0 | Jacobs |
| g. Duct Work Cost (included in SCR Cost) | | $0 | Jacobs |
| h. Plot Plant Installation Factor (included in SCR Cost) | | 1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $24,768,927 | *Calculation* |
| i. SIS Instrumentation (included in SCR Cost) | | $4,161,000 | Jacobs |
| j. Instrumentation (included in SCR Cost) | | $0 | Jacobs |
| k. Local Sales tax (included in SCR Cost) | | $0 | Jacobs |
| l. Freight (included in SCR Cost) | | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $28,929,927 | |
| **INDIRECT COSTS** | | | |
| B. Indirect Installation | | | |
| a. General Facilities (included in SCR Cost) | | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in SCR Cost) | | $0 | Jacobs |
| c. Process Contingency (included in SCR Cost) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| C. Project Contingency (included in SCR Cost) | | $0 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $28,929,927 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in SCR Cost) | | $0 | Jacobs |
| H. Inventory Capital (included in SCR Cost) | | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in SCR Cost) | | $0 | Jacobs |
| J. CEMS Installation (included in SCR Cost) | | $1,871,500 | Jacobs |
| K. Cost for set-up of multple units (only one SCR used) | | $0 | Jacobs |
| L. Lost Production due to extended turnaround | | $23,750,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $54,551,427 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$5,149,269** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT ANNUAL COSTS (DAC)** | | | |
| M. Labor for operations (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| N. Supervisory Labor (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Maintenance Labor and Costs (0.015*TCI) | | $462,021 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. CEMS operation (assumed none add'l for SCR) | | $0 | Jacobs |
| Q. Consumables - Reagent | | $16,044 | Jacobs |
| R. Consumables - Catalyst (annualized over 5 years @ 7% interest) | | $29,657 | Jacobs |
| S. Utility costs - fan & ammonia vaporization (electricity) | | $103,467 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | | $611,189 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | | |
| T. Property Taxes (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| U. Overhead (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Insurance (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Administrative charges (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Payroll Overhead (0.6*labor costs) | | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Y. Plant Overhead (assumed negligible for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | | **$611,189** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | | **$5,760,458** | *Calculation* |
| Uncontrolled emissions | tons/year | 132.1 | BP Estimation for BART |
| Emissions w/SCR | tons/year | 8.1 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from baseline | Percent | 93.9 | *Calculation* |
| Total Emissions Reduction | tons/year | 124.0 | *Calculation* |
| ***Cost per ton Controlled*** | ***$/ton*** | **$ 46,449** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).
Section 4.2 Chapter 2: Selective Catalytic Reduction (October 2000)

Note: The Select cost analysis obtained vendor estimates for primary equipment and performed a more project-specific cost analysis for installation of SCR on this unit. Due to the accuracy of the project-specific cost estimate, a Contingency of between approximately 17% and 20% was utilized depending upon the unit.

BP BART

SCR Cost Effectiveness Calculation - #2 Reforming Furnace (South H2 Plant)

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Equipment Design Considerations | | | |
| a. SCR Cost (including adjustment for SCR reactor height and bypass installation) | | $23,634,480 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | | $999,065 | Jacobs |
| c. Initial Charge of Catalyst (included in SCR Cost) | | $115,520 | Jacobs |
| d. ID Fan Cost (included in SCR Cost) | | $0 | Jacobs |
| e. ID Fan Motor Cost (included in SCR Cost) | | $0 | Jacobs |
| f. Convection Section Cost (included in SCR Cost) | | $0 | Jacobs |
| g. Duct Work Cost (included in SCR Cost) | | $0 | Jacobs |
| h. Plot Plant Installation Factor (included in SCR Cost) | | 1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $24,749,065 | *Calculation* |
| i. SIS Instrumentation (included in SCR Cost) | | $4,161,000 | Jacobs |
| j. Instrumentation (included in SCR Cost) | | $0 | Jacobs |
| k. Local Sales tax (included in SCR Cost) | | $0 | Jacobs |
| l. Freight (included in SCR Cost) | | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $28,910,065 | |
| **INDIRECT COSTS** | | | |
| B. Indirect Installation | | | |
| a. General Facilities (included in SCR Cost) | | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in SCR Cost) | | $0 | Jacobs |
| c. Process Contingency (included in SCR Cost) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| C. Project Contingency (included in SCR Cost) | | $0 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $28,910,065 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in SCR Cost) | | $0 | Jacobs |
| H. Inventory Capital (included in SCR Cost) | | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in SCR Cost) | | $0 | Jacobs |
| J. CEMS Installation | | $1,871,500 | Jacobs |
| K. Cost for set-up of multple units (only one SCR used) | | $0 | Jacobs |
| L. Lost Production due to extended turnaround | | $23,750,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $54,531,565 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$5,147,394** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT ANNUAL COSTS (DAC)** | | | |
| M. Labor for operations (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| N. Supervisory Labor (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Maintenance Labor and Costs (0.015*TCI) | | $461,723 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. CEMS operation (assumed none add'l for SCR) | | $0 | Jacobs |
| Q. Consumables - Reagent | | $15,731 | Jacobs |
| R. Consumables - Catalyst (annualized over 5 years @ 7% interest) | | $29,657 | Jacobs |
| S. Utility costs - fan & ammonia vaporization (electricity) | | $101,450 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | | $608,562 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | | |
| T. Property Taxes (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| U. Overhead (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Insurance (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Administrative charges (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Payroll Overhead (0.6*labor costs) | | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Y. Plant Overhead (assumed negligible for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | | **$608,562** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | | **$5,755,956** | *Calculation* |
| Uncontrolled emissions | tons/year | 129.5 | BP Estimation for BART |
| Emissions w/SCR | tons/year | 7.9 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from baseline | Percent | 93.9 | *Calculation* |
| Total Emissions Reduction | tons/year | 121.6 | *Calculation* |
| ***Cost per ton Controlled*** | ***$/ton*** | **$ 47,320** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).
Section 4.2 Chapter 2: Selective Catalytic Reduction (October 2000)

Note: The Select cost analysis obtained vendor estimates for primary equipment and performed a more project-specific cost analysis for installation of SCR on this unit. Due to the accuracy of the project-specific cost estimate, a Contingency of between approximately 17% and 20% was utilized depending upon the unit.

BP BART
SCR Cost Effectiveness Calculation - R-1 HC Reactor Heater
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Equipment Design Considerations | | |
| a. Reactor Cost (including adjustment for SCR reactor height and bypass installation) | $1,297,470 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | $1,207,250 | Jacobs |
| c. Initial Charge of Catalyst | $53,033 | Jacobs |
| d. ID Fan Cost | $597,788 | Jacobs |
| e. ID Fan Motor Cost | $115,850 | Jacobs |
| f. Convection Section Cost | $1,925,828 | Jacobs |
| g. Duct Work Cost | $970,329 | Jacobs |
| h. Plot Plant Installation Factor (addressed ease of installation - new or retrofit) | 1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $6,167,550 | *Calculation* |
| i. SIS Instrumentation | $1,250,000 | Jacobs |
| j. CEMS Installation (included in SCR Cost) | $0 | Jacobs |
| k. Local Sales tax (included in Project Contingency) | $0 | Jacobs |
| l. Freight (included in SCR cost) | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $7,417,550 | |
| **INDIRECT COSTS** | | |
| B. Indirect Installation | | |
| a. General Facilities (included in Project Contingency) | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in Project Contingency) | $0 | Jacobs |
| c. Process Contingency (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | *Calculation* |
| C. Project Contingency ([DCC + ICC]*0.40) | $2,967,020 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $10,384,570 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in Project Contingency) | $0 | Jacobs |
| H. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in SCR Cost) | $0 | Jacobs |
| J. Cost for set-up of multple units | $0 | Jacobs |
| K. Lost Production due to extended turnaround | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | $10,384,570 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$980,230** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT ANNUAL COSTS (DAC)** | | |
| M. Labor for operations (assumed none add'l for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| N. Supervisory Labor (assumed none add'l for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Maintenance Labor and Costs (0.015*TCI) | $155,769 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. CEMS operation (assumed none add'l for SCR) | $0 | Jacobs |
| Q. Consumables - Reagent | $1,174 | Jacobs |
| R. Consumables - Catalyst (annualized over 5 years @ 7% interest) | $12,934 | Jacobs |
| S. Utility costs - fan & ammonia vaporization (electricity) | $26,090 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | $195,966 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | |
| T. Property Taxes (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| U. Overhead (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Insurance (assumed insignificant for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Administrative charges (assumed insignificant for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Payroll Overhead (0.6*labor costs) | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Y. Plant Overhead (assumed negligible for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | **$195,966** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | **$1,176,196** | *Calculation* |
| Uncontrolled emissions tons/year | 7.8 | BP Estimation for BART |
| Emissions w/SCR tons/year | 2.3 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from baseline Percent | 70.1 | *Calculation* |
| Total Emissions Reduction tons/year | 5.5 | *Calculation* |
| ***Cost per ton Controlled $/ton*** | **$ 214,726** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).
Section 4.2 Chapter 2: Selective Catalytic Reduction (October 2000)

Note: The Appraise cost analysis estimated costs for the reactor, duct work, ammonia delivery system, catalyst, and ID fan. Other items, such as sales tax, freight, engineering, and others, were assumed to be addressed en masse in the Project Contingency of 40%.

BP BART
SCR Cost Effectiveness Calculation - R-4 HC Reactor Heater
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Equipment Design Considerations | | |
| a. Reactor Cost (including adjustment for SCR reactor height and bypass installation) | $837,267 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | $1,213,524 | Jacobs |
| c. Initial Charge of Catalyst | $45,414 | Jacobs |
| d. ID Fan Cost | $428,708 | Jacobs |
| e. ID Fan Motor Cost | $83,083 | Jacobs |
| f. Convection Section Cost | $0 | Jacobs |
| g. Duct Work Cost | $735,525 | Jacobs |
| h. Plot Plant Installation Factor (addressed ease of installation - new or retrofit) | 1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $3,343,521 | *Calculation* |
| i. SIS Instrumentation (already partially installed) | $500,000 | Jacobs |
| j. CEMS Installation (included in SCR Cost) | $0 | Jacobs |
| k. Local Sales tax (included in Project Contingency) | $0 | Jacobs |
| l. Freight (included in SCR cost) | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $3,843,521 | |
| **INDIRECT COSTS** | | |
| B. Indirect Installation | | |
| a. General Facilities (included in Project Contingency) | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in Project Contingency) | $0 | Jacobs |
| c. Process Contingency (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | *Calculation* |
| C. Project Contingency ([DCC + ICC]*0.40) | $1,537,408 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $5,380,929 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in Project Contingency) | $0 | Jacobs |
| H. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in SCR Cost) | $0 | Jacobs |
| J. Cost for set-up of multple units | $0 | Jacobs |
| K. Lost Production due to extended turnaround | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | $5,380,929 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$507,922** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT ANNUAL COSTS (DAC)** | | |
| M. Labor for operations (assumed none add'l for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| N. Supervisory Labor (assumed none add'l for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Maintenance Labor and Costs (0.015*TCI) | $80,714 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. CEMS operation (assumed none add'l for SCR) | $0 | Jacobs |
| Q. Consumables - Reagent | $2,189 | Jacobs |
| R. Consumables - Catalyst (annualized over 5 years @ 7% interest) | $11,076 | Jacobs |
| S. Utility costs - fan & ammonia vaporization (electricity) | $17,704 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | $111,684 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | |
| T. Property Taxes (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| U. Overhead (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Insurance (assumed insignificant for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Administrative charges (assumed insignificant for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Payroll Overhead (0.6*labor costs) | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Y. Plant Overhead (assumed negligible for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | **$111,684** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | **$619,605** | *Calculation* |
| Uncontrolled emissions tons/year | 18.0 | BP Estimation for BART |
| Emissions w/SCR tons/year | 1.1 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from baseline Percent | 93.9 | *Calculation* |
| Total Emissions Reduction tons/year | 16.9 | *Calculation* |
| ***Cost per ton Controlled $/ton*** | **$ 36,620** | *Calculation* |

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Section 4.2 Chapter 2: Selective Catalytic Reduction (October 2000)

Note: The Appraise cost analysis estimated costs for the reactor, duct work, ammonia delivery system, catalyst, and ID fan. Other items, such as sales tax, freight, engineering, and others, were assumed to be addressed en masse in the Project Contingency of 40%.

BP BART

SCR Cost Effectiveness Calculation - 1st Stage HC Fractionator Reboiler

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Equipment Design Considerations | | | |
| a. Reactor Cost (including adjustment for SCR reactor height and bypass installation) | | $2,320,407 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | | $1,298,537 | Jacobs |
| c. Initial Charge of Catalyst | | $232,836 | Jacobs |
| d. ID Fan Cost | | $1,466,821 | Jacobs |
| e. ID Fan Motor Cost | | $284,268 | Jacobs |
| f. Convection Section Cost | | $3,816,576 | Jacobs |
| g. Duct Work Cost | | $1,438,232 | Jacobs |
| h. Plot Plant Installation Factor (addressed ease of installation - new or retrofit) | | 1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $10,857,677 | *Calculation* |
| i. SIS Instrumentation | | $1,070,000 | Jacobs |
| j. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| k. Local Sales tax (included in Project Contingency) | | $0 | Jacobs |
| l. Freight (included in Project Contingency) | | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $11,927,677 | |
| **INDIRECT COSTS** | | | |
| B. Indirect Installation | | | |
| a. General Facilities (included in Project Contingency) | | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in Project Contingency) | | $0 | Jacobs |
| c. Process Contingency (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| C. Project Contingency ([DCC + ICC]*0.40) | | $4,343,071 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $16,270,748 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in Project Contingency) | | $0 | Jacobs |
| H. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| J. CEMS Installation | | $1,710,000 | Jacobs |
| K. Cost for set-up of multple units | | $0 | Jacobs |
| L. Lost Production due to extended turnaround | | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $17,980,748 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$1,697,255** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT ANNUAL COSTS (DAC)** | | | |
| M. Labor for operations (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| N. Supervisory Labor (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Maintenance Labor and Costs (0.015*TCI) | | $269,711 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. CEMS operation (assumed none add'l for SCR) | | $0 | Jacobs |
| Q. Consumables - Reagent | | $15,950 | Jacobs |
| R. Consumables - Catalyst (annualized over 5 years @ 7% interest) | | $56,787 | Jacobs |
| S. Utility costs - fan & ammonia vaporization (electricity) | | $62,298 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | | $404,746 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | | |
| T. Property Taxes (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| U. Overhead (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Insurance (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Administrative charges (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Payroll Overhead (0.6*labor costs) | | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Y. Plant Overhead (assumed negligible for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | | **$404,746** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | | **$2,102,001** | *Calculation* |
| Uncontrolled emissions | tons/year | 113.6 | BP Estimation for BART |
| Emissions w/SCR | tons/year | 5.7 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from baseline | Percent | 95.0 | *Calculation* |
| Total Emissions Reduction | tons/year | 108.0 | *Calculation* |
| ***Cost per ton Controlled*** | ***$/ton*** | **$ 19,470** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quality Planning and Standards (OAQPS).
Section 4.2 Chapter 2: Selective Catalytic Reduction (October 2000)

Note: The Appraise cost analysis estimated costs for the reactor, duct work, ammonia delivery system, catalyst, and ID fan. Other items, such as sales tax, freight, engineering, and others, were assumed to be addressed en masse in the Project Contingency of 40%.

BP BART
SCR Cost Effectiveness Calculation - 2nd Stage HC Fractionator Reboiler
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Equipment Design Considerations | | | |
| a. Reactor Cost (including adjustment for SCR reactor height and bypass installation) | | $2,058,463 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | | $1,235,879 | Jacobs |
| c. Initial Charge of Catalyst | | $177,842 | Jacobs |
| d. ID Fan Cost | | $674,406 | Jacobs |
| e. ID Fan Motor Cost | | $130,699 | Jacobs |
| f. Convection Section Cost | | $791,897 | Jacobs |
| g. Duct Work Cost | | $1,072,912 | Jacobs |
| h. Plot Plant Installation Factor (addressed ease of installation - new or retrofit) | | 1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $6,142,098 | *Calculation* |
| i. SIS Instrumentation | | $1,250,000 | Jacobs |
| j. CEMS Installation (included in SCR Cost) | | $0 | Jacobs |
| k. Local Sales tax (included in Project Contingency) | | $0 | Jacobs |
| l. Freight (included in SCR cost) | | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $7,392,098 | |
| **INDIRECT COSTS** | | | |
| B. Indirect Installation | | | |
| a. General Facilities (included in Project Contingency) | | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in Project Contingency) | | $0 | Jacobs |
| c. Process Contingency (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| C. Project Contingency ([DCC + ICC]*0.40) | | $2,956,839 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $10,348,937 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in Project Contingency) | | $0 | Jacobs |
| H. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in SCR Cost) | | $0 | Jacobs |
| J. Cost for set-up of multple units | | $0 | Jacobs |
| K. Lost Production due to extended turnaround | | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $10,348,937 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$976,866** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT ANNUAL COSTS (DAC)** | | | |
| M. Labor for operations (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| N. Supervisory Labor (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Maintenance Labor and Costs (0.015*TCI) | | $155,234 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. CEMS operation (assumed none add'l for SCR) | | $0 | Jacobs |
| Q. Consumables - Reagent | | $5,808 | Jacobs |
| R. Consumables - Catalyst (annualized over 5 years @ 7% interest) | | $43,374 | Jacobs |
| S. Utility costs - fan & ammonia vaporization (electricity) | | $39,731 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | | $244,147 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | | |
| T. Property Taxes (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| U. Overhead (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Insurance (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Administrative charges (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Payroll Overhead (0.6*labor costs) | | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Y. Plant Overhead (assumed negligible for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | | **$244,147** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | | **$1,221,013** | *Calculation* |
| Uncontrolled emissions | tons/year | 36.1 | BP Estimation for BART |
| Emissions w/SCR | tons/year | 3.8 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from baseline | Percent | 89.5 | *Calculation* |
| Total Emissions Reduction | tons/year | 32.3 | *Calculation* |
| ***Cost per ton Controlled*** | ***$/ton*** | **$ 37,810** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quality Planning and Standards (OAQPS).
Section 4.2 Chapter 2: Selective Catalytic Reduction (October 2000)

Note: The Appraise cost analysis estimated costs for the reactor, duct work, ammonia delivery system, catalyst, and ID fan. Other items, such as sales tax, freight, engineering, and others, were assumed to be addressed en masse in the Project Contingency of 40%.

BP BART
ULNB with SCR Cost Effectiveness Calculation - Coker Charge Heater (#1 North)
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Equipment Design Considerations | | | |
| a. Reactor Cost (including adjustment for SCR reactor height and bypass installation) | | $1,986,263 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | | $1,230,686 | Jacobs |
| c. Initial Charge of Catalyst | | $186,670 | Jacobs |
| d. ID Fan Cost | | $838,517 | Jacobs |
| e. ID Fan Motor Cost | | $162,503 | Jacobs |
| f. Convection Section Cost | | $0 | Jacobs |
| g. Duct Work Cost | | $1,286,440 | Jacobs |
| h. Plot Plant Installation Factor (addressed ease of installation - new or retrofit) | | 1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $5,691,079 | *Calculation* |
| i. SIS Instrumentation | | $1,250,000 | Jacobs |
| j. CEMS Installation (included in SCR Cost) | | $0 | Jacobs |
| k. Local Sales tax (included in Project Contingency) | | $0 | Jacobs |
| l. Freight (included in SCR cost) | | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $6,941,079 | |
| **INDIRECT COSTS** | | | |
| B. Indirect Installation | | | |
| a. General Facilities (included in Project Contingency) | | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in Project Contingency) | | $0 | Jacobs |
| c. Process Contingency (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| C. Project Contingency ([DCC + ICC]*0.40) | | $2,776,432 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $9,717,511 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in Project Contingency) | | $0 | Jacobs |
| H. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in SCR Cost) | | $0 | Jacobs |
| J. Cost for set-up of multple units | | $0 | Jacobs |
| K. Lost Production due to extended turnaround | | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $9,717,511 | *Calculation* |
| ULNB Total Capital Investment (less SIS) | | $2,823,640 | |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$1,183,796** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT ANNUAL COSTS (DAC)** | | | |
| ULNB Direct Annual Costs | | $96,876 | ULNB BART Calculation |
| M. Labor for operations (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| N. Supervisory Labor (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Maintenance Labor and Costs (0.015*TCI less lost production) | | $145,763 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. CEMS operation (assumed none add'l for SCR) | | $0 | Jacobs |
| Q. Consumables - Reagent | | $3,096 | Jacobs |
| R. Consumables - Catalyst (annualized over 5 years @ 7% interest) | | $45,527 | Jacobs |
| S. Utility costs - fan & ammonia vaporization (electricity) | | $47,709 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | | $338,971 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | | |
| ULNB Indirect Annual Costs | | $0 | ULNB BART Calculation |
| T. Property Taxes (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| U. Overhead (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Insurance (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Administrative charges (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Payroll Overhead (0.6*labor costs) | | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Y. Plant Overhead (assumed negligible for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | | **$338,971** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | | **$1,522,767** | *Calculation* |
| Uncontrolled emissions | tons/year | 38.8 | BP Estimation for BART |
| Emissions w/ULNB only | tons/year | 21.9 | BART analysis |
| Emissions w/ULNB + SCR | tons/year | 3.7 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from ULNB | Percent | 82.9 | *Calculation* |
| Overall Reduction from Uncontrolled | Percent | 90.4 | *Calculation* |
| Total Emissions Reduction for SCR + ULNB | tons/year | 35.0 | *Calculation* |
| ***Cost per ton Controlled*** | ***$/ton*** | **$ 43,460** | *Calculation* |

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Section 4.2 Chapter 2: Selective Catalytic Reduction (October 2000)

Calculation assumes that the LNB installation and cost will not change as a result of the SCR installation. The SCR costs were adjusted to account for the lower post-LNB inlet NOx concentration resulting in needing less catalyst and less ammonia consumption.

BP BART
ULNB with SCR Cost Effectiveness Calculation - Coker Charge Heater (#2 South)
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Equipment Design Considerations | | | |
| a. Reactor Cost (including adjustment for SCR reactor height and bypass installation) | | $1,986,263 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | | $1,231,119 | Jacobs |
| c. Initial Charge of Catalyst | | $188,522 | Jacobs |
| d. ID Fan Cost | | $838,517 | Jacobs |
| e. ID Fan Motor Cost | | $162,503 | Jacobs |
| f. Convection Section Cost | | $0 | Jacobs |
| g. Duct Work Cost | | $1,286,440 | Jacobs |
| h. Plot Plant Installation Factor (addressed ease of installation - new or retrofit) | | 1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $5,693,365 | *Calculation* |
| i. SIS Instrumentation | | $1,250,000 | Jacobs |
| j. CEMS Installation (included in SCR Cost) | | $0 | Jacobs |
| k. Local Sales tax (included in Project Contingency) | | $0 | Jacobs |
| l. Freight (included in SCR cost) | | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $6,943,365 | |
| **INDIRECT COSTS** | | | |
| B. Indirect Installation | | | |
| a. General Facilities (included in Project Contingency) | | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in Project Contingency) | | $0 | Jacobs |
| c. Process Contingency (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| C. Project Contingency ([DCC + ICC]*0.40) | | $2,777,346 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $9,720,711 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in Project Contingency) | | $0 | Jacobs |
| H. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in SCR Cost) | | $0 | Jacobs |
| J. Cost for set-up of multple units | | $0 | Jacobs |
| K. Lost Production due to extended turnaround | | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $9,720,711 | *Calculation* |
| ULNB Total Capital Investment (less SIS) | | $2,823,640 | |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$1,184,098** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT ANNUAL COSTS (DAC)** | | | |
| ULNB Direct Annual Costs | | $96,876 | ULNB BART Calculation |
| M. Labor for operations (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| N. Supervisory Labor (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Maintenance Labor and Costs (0.015*TCI less lost production) | | $145,811 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. CEMS operation (assumed none add'l for SCR) | | $0 | Jacobs |
| Q. Consumables - Reagent | | $3,140 | Jacobs |
| R. Consumables - Catalyst (annualized over 5 years @ 7% interest) | | $45,979 | Jacobs |
| S. Utility costs - fan & ammonia vaporization (electricity) | | $47,788 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | | $339,593 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | | |
| ULNB Indirect Annual Costs | | $0 | ULNB BART Calculation |
| T. Property Taxes (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| U. Overhead (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Insurance (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Administrative charges (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Payroll Overhead (0.6*labor costs) | | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Y. Plant Overhead (assumed negligible for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | | **$339,593** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | | **$1,523,691** | *Calculation* |
| Uncontrolled emissions | tons/year | 39.5 | BP Estimation for BART |
| Emissions w/ULNB only | tons/year | 22.3 | BART analysis |
| Emissions w/ULNB + SCR | tons/year | 3.8 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from ULNB | Percent | 82.9 | *Calculation* |
| Overall Reduction from Uncontrolled | Percent | 90.4 | *Calculation* |
| Total Emissions Reduction for SCR + ULNB | tons/year | 35.7 | *Calculation* |
| ***Cost per ton Controlled*** | ***$/ton*** | **$ 42,738** | *Calculation* |

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Section 4.2 Chapter 2: Selective Catalytic Reduction (October 2000)

Calculation assumes that the LNB installation and cost will not change as a result of the SCR installation. The SCR costs were adjusted to account for the lower post-LNB inlet NOx concentration resulting in needing less catalyst and less ammonia consumption.

BP BART
ULNB with SCR Cost Effectiveness Calculation - #1 Reforming Furnace (North H2 Plant)
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Equipment Design Considerations | | | |
| a. SCR Cost (including adjustment for SCR reactor height and bypass installation) | | $23,634,480 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | | $1,018,927 | Jacobs |
| c. Initial Charge of Catalyst (included in SCR Cost) | | $96,520 | Jacobs |
| d. ID Fan Cost (included in SCR Cost) | | $0 | Jacobs |
| e. ID Fan Motor Cost (included in SCR Cost) | | $0 | Jacobs |
| f. Convection Section Cost (included in SCR Cost) | | $0 | Jacobs |
| g. Duct Work Cost (included in SCR Cost) | | $0 | Jacobs |
| h. Plot Plant Installation Factor (included in SCR Cost) | | 1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $24,749,927 | *Calculation* |
| i. SIS Instrumentation | | $4,161,000 | Jacobs |
| j. Instrumentation (included in SCR Cost) | | $0 | Jacobs |
| k. Local Sales tax (included in SCR Cost) | | $0 | Jacobs |
| l. Freight (included in SCR Cost) | | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $28,910,927 | |
| **INDIRECT COSTS** | | | |
| B. Indirect Installation | | | |
| a. General Facilities (included in SCR Cost) | | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in SCR Cost) | | $0 | Jacobs |
| c. Process Contingency (included in SCR Cost) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| C. Project Contingency (included in SCR Cost) | | $0 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $28,910,927 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in SCR Cost) | | $0 | Jacobs |
| H. Inventory Capital (included in SCR Cost) | | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in SCR Cost) | | $0 | Jacobs |
| J. CEMS Installation | | $1,871,500 | Jacobs |
| K. Cost for set-up of multple units (only one SCR used) | | $0 | Jacobs |
| L. Lost Production due to extended turnaround | | $23,750,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $54,532,427 | *Calculation* |
| ULNB Total Capital Investment (less SIS & CEMS) | | $9,947,500 | |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$6,086,449** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT ANNUAL COSTS (DAC)** | | | |
| ULNB Direct Annual Costs | | $168,863 | ULNB BART Calculation |
| N. Labor for operations (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Supervisory Labor (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. Maintenance Labor and Costs (0.015*TCI less lost production) | | $461,736 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| Q. CEMS operation (assumed none add'l for SCR) | | $0 | Jacobs |
| R. Consumables - Reagent | | $9,426 | Jacobs |
| S. Consumables - Catalyst (annualized over 5 years @ 7% interest) | | $27,340 | Jacobs |
| T. Utility costs - fan & ammonia vaporization (electricity) | | $91,615 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | | $758,980 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | | |
| ULNB Indirect Annual Costs | | $0 | ULNB BART Calculation |
| U. Property Taxes (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Overhead (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Insurance (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Administrative charges (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| Y. Payroll Overhead (0.6*labor costs) | | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Z. Plant Overhead (assumed negligible for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | | **$758,980** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | | **$6,845,429** | *Calculation* |
| Uncontrolled emissions | tons/year | 132.1 | BP Estimation for BART |
| Emissions w/ULNB only | tons/year | 74.1 | BART analysis |
| Emissions w/ULNB + SCR | tons/year | 8.1 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from ULNB | Percent | 89.1 | *Calculation* |
| Overall Reduction from Uncontrolled | Percent | 93.9 | *Calculation* |
| Total Emissions Reduction for SCR + ULNB | tons/year | 124.0 | *Calculation* |
| ***Cost per ton Controlled*** | ***$/ton*** | **$ 55,197** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).
Section 4.2 Chapter 2: Selective Catalytic Reduction (October 2000)

Calculation assumes that the LNB installation and cost will not change as a result of the SCR installation. The SCR costs were adjusted to account for the lower post-LNB inlet NOx concentration resulting in needing less catalyst and less ammonia consumption.

BP BART
ULNB with SCR Cost Effectiveness Calculation - #2 Reforming Furnace (South H2 Plant)
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Equipment Design Considerations | | | |
| a. SCR Cost (including adjustment for SCR reactor height and bypass installation) | | $23,634,480 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | | $999,065 | Jacobs |
| c. Initial Charge of Catalyst (included in SCR Cost) | | $96,520 | Jacobs |
| d. ID Fan Cost (included in SCR Cost) | | $0 | Jacobs |
| e. ID Fan Motor Cost (included in SCR Cost) | | $0 | Jacobs |
| f. Convection Section Cost (included in SCR Cost) | | $0 | Jacobs |
| g. Duct Work Cost (included in SCR Cost) | | $0 | Jacobs |
| h. Plot Plant Installation Factor (included in SCR Cost) | | 1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $24,730,065 | *Calculation* |
| i. SIS Instrumentation | | $4,161,000 | Jacobs |
| j. Instrumentation (included in SCR Cost) | | $0 | Jacobs |
| k. Local Sales tax (included in SCR Cost) | | $0 | Jacobs |
| l. Freight (included in SCR Cost) | | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $28,891,065 | |
| **INDIRECT COSTS** | | | |
| B. Indirect Installation | | | |
| a. General Facilities (included in SCR Cost) | | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in SCR Cost) | | $0 | Jacobs |
| c. Process Contingency (included in SCR Cost) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| C. Project Contingency (included in SCR Cost) | | $0 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $28,891,065 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in SCR Cost) | | $0 | Jacobs |
| H. Inventory Capital (included in SCR Cost) | | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in SCR Cost) | | $0 | Jacobs |
| J. CEMS Installation | | $1,871,500 | Jacobs |
| K. Cost for set-up of multple units (only one SCR used) | | $0 | Jacobs |
| L. Lost Production due to extended turnaround | | $23,750,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $54,512,565 | *Calculation* |
| ULNB Total Capital Investment (less SIS & CEMS) | | $9,947,500 | |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$6,084,574** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT ANNUAL COSTS (DAC)** | | | |
| ULNB Direct Annual Costs | | $168,863 | ULNB BART Calculation |
| N. Labor for operations (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Supervisory Labor (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. Maintenance Labor and Costs (0.015*TCI less lost production) | | $461,438 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| Q. CEMS operation (assumed none add'l for SCR) | | $0 | Jacobs |
| R. Consumables - Reagent | | $9,245 | Jacobs |
| S. Consumables - Catalyst (annualized over 5 years @ 7% interest) | | $27,340 | Jacobs |
| T. Utility costs - fan & ammonia vaporization (electricity) | | $89,834 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | | $756,720 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | | |
| ULNB Indirect Annual Costs | | $0 | ULNB BART Calculation |
| U. Property Taxes (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Overhead (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Insurance (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Administrative charges (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| Y. Payroll Overhead (0.6*labor costs) | | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Z. Plant Overhead (assumed negligible for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | | **$756,720** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | | **$6,841,294** | *Calculation* |
| Uncontrolled emissions | tons/year | 129.5 | BP Estimation for BART |
| Emissions w/ULNB only | tons/year | 72.7 | BART analysis |
| Emissions w/ULNB + SCR | tons/year | 7.9 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from ULNB | Percent | 89.1 | *Calculation* |
| Overall Reduction from Uncontrolled | Percent | 93.9 | *Calculation* |
| Total Emissions Reduction for SCR + ULNB | tons/year | 121.6 | *Calculation* |
| ***Cost per ton Controlled*** | ***$/ton*** | **$ 56,242** | *Calculation* |

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Section 4.2 Chapter 2: Selective Catalytic Reduction (October 2000)

Calculation assumes that the LNB installation and cost will not change as a result of the SCR installation. The SCR costs were adjusted to account for the lower post-LNB inlet NOx concentration resulting in needing less catalyst and less ammonia consumption.

BP BART
ULNB with SCR Cost Effectiveness Calculation - 1st Stage HC Fractionator Reboiler
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Equipment Design Considerations | | | |
| a. Reactor Cost (including adjustment for SCR reactor height and bypass installation) | | $2,199,991 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | | $1,249,204 | Jacobs |
| c. Initial Charge of Catalyst | | $180,508 | Jacobs |
| d. ID Fan Cost | | $1,466,821 | Jacobs |
| e. ID Fan Motor Cost | | $284,268 | Jacobs |
| f. Convection Section Cost | | $3,816,576 | Jacobs |
| g. Duct Work Cost | | $1,438,232 | Jacobs |
| h. Plot Plant Installation Factor (addressed ease of installation - new or retrofit) | | 1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $10,635,599 | *Calculation* |
| i. SIS Instrumentation | | $1,070,000 | Jacobs |
| j. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| k. Local Sales tax (included in Project Contingency) | | $0 | Jacobs |
| l. Freight (included in Project Contingency) | | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $11,705,599 | |
| **INDIRECT COSTS** | | | |
| B. Indirect Installation | | | |
| a. General Facilities (included in Project Contingency) | | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in Project Contingency) | | $0 | Jacobs |
| c. Process Contingency (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| C. Project Contingency ([DCC + ICC]*0.40) | | $4,254,240 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $15,959,839 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in Project Contingency) | | $0 | Jacobs |
| H. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| J. CEMS Installation | | $1,710,000 | Jacobs |
| K. Cost for set-up of multple units | | $0 | Jacobs |
| L. Lost Production due to extended turnaround | | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $17,669,839 | *Calculation* |
| ULNB Total Capital Investment (less SIS & CEMS) | | $4,411,000 | |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$2,084,275** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT ANNUAL COSTS (DAC)** | | | |
| ULNB Direct Annual Costs | | $125,115 | ULNB BART Calculation |
| M. Labor for operations (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| N. Supervisory Labor (assumed none add'l for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Maintenance Labor and Costs (0.015*TCI less lost production) | | $265,048 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. CEMS operation (assumed none add'l for SCR) | | $0 | Jacobs |
| Q. Consumables - Reagent | | $4,965 | Jacobs |
| R. Consumables - Catalyst (annualized over 5 years @ 7% interest) | | $44,024 | Jacobs |
| S. Utility costs - fan & ammonia vaporization (electricity) | | $42,621 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | | $481,772 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | | |
| ULNB Indirect Annual Costs | | $0 | ULNB BART Calculation |
| T. Property Taxes (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| U. Overhead (assumed none for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Insurance (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Administrative charges (assumed insignificant for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Payroll Overhead (0.6*labor costs) | | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Y. Plant Overhead (assumed negligible for SCR) | | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | | **$481,772** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | | **$2,566,047** | *Calculation* |
| Uncontrolled emissions | tons/year | 113.6 | BP Estimation for BART |
| Emissions w/ULNB only | tons/year | 37.9 | BART analysis |
| Emissions w/ULNB + SCR | tons/year | 4.5 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from ULNB | Percent | 88.0 | *Calculation* |
| Overall Reduction from Uncontrolled | Percent | 96.0 | *Calculation* |
| Total Emissions Reduction for SCR + ULNB | tons/year | 109.1 | *Calculation* |
| ***Cost per ton Controlled*** | ***$/ton*** | **$ 23,518** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).
Section 4.2 Chapter 2: Selective Catalytic Reduction (October 2000)

Calculation assumes that the LNB installation and cost will not change as a result of the SCR installation. The SCR costs were adjusted to account for the lower post-LNB inlet NOx concentration resulting in needing less catalyst and less ammonia consumption.

BP BART
ULNB with SCR Cost Effectiveness Calculation - 2nd Stage HC Fractionator Reboiler
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Equipment Design Considerations | | |
| a. Reactor Cost (including adjustment for SCR reactor height and bypass installation) | $2,058,463 | Jacobs |
| b. Ammonia Delivery System (includes adjustment for ammonia flow rate) | $1,237,934 | Jacobs |
| c. Initial Charge of Catalyst | $151,362 | Jacobs |
| d. ID Fan Cost | $674,406 | Jacobs |
| e. ID Fan Motor Cost | $130,699 | Jacobs |
| f. Convection Section Cost | $791,897 | Jacobs |
| g. Duct Work Cost | $1,072,912 | Jacobs |
| h. Plot Plant Installation Factor (addressed ease of installation - new or retrofit) | 1 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $6,117,673 | *Calculation* |
| i. SIS Instrumentation | $1,250,000 | Jacobs |
| j. CEMS Installation (included in SCR Cost) | $0 | Jacobs |
| k. Local Sales tax (included in Project Contingency) | $0 | Jacobs |
| l. Freight (included in SCR cost) | $0 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $7,367,673 | |
| **INDIRECT COSTS** | | |
| B. Indirect Installation | | |
| a. General Facilities (included in Project Contingency) | $0 | Jacobs |
| b. Engineering and Home Office Fees (included in Project Contingency) | $0 | Jacobs |
| c. Process Contingency (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | *Calculation* |
| C. Project Contingency ([DCC + ICC]*0.40) | $2,947,069 | Jacobs - ROM ± 50% |
| ***D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $10,314,743 | *Calculation* |
| E. Allowance for Funds During Construction (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| F. Royalty Allowance (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, Table 2.5 |
| G. Preproduction Cost (included in Project Contingency) | $0 | Jacobs |
| H. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| I. Initial Catalyst and Chemicals (included in SCR Cost) | $0 | Jacobs |
| J. Cost for set-up of multple units | $0 | Jacobs |
| K. Lost Production due to extended turnaround | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | $10,314,743 | *Calculation* |
| ULNB Total Capital Investment (less SIS & CEMS) | $777,000 | |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$1,046,982** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT ANNUAL COSTS (DAC)** | | |
| ULNB Direct Annual Costs | $37,905 | ULNB BART Calculation |
| M. Labor for operations (assumed none add'l for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| N. Supervisory Labor (assumed none add'l for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| O. Maintenance Labor and Costs (0.015*TCI less lost production) | $154,721 | OAQPS, Section 4.2, Chapter 2, page 2-45 |
| P. CEMS operation (assumed none add'l for SCR) | $0 | Jacobs |
| Q. Consumables - Reagent | $3,828 | Jacobs |
| R. Consumables - Catalyst (annualized over 5 years @ 7% interest) | $36,916 | Jacobs |
| S. Utility costs - fan & ammonia vaporization (electricity) | $36,184 | Jacobs |
| ***Total Direct Annual Costs [DAC]*** | $269,553 | |
| **INDIRECT ANNUAL COSTS (IDAC)** | | |
| ULNB Indirect Annual Costs | $0 | ULNB BART Calculation |
| T. Property Taxes (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| U. Overhead (assumed none for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| V. Insurance (assumed insignificant for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| W. Administrative charges (assumed insignificant for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| X. Payroll Overhead (0.6*labor costs) | $0 | OAQPS, Section 3.1, Chapter 1, Table 1.6 and others |
| Y. Plant Overhead (assumed negligible for SCR) | $0 | OAQPS, Section 4.2, Chapter 2, page 2-48 |
| ***Total Indirect Annual Costs (Annualized: 20 years @ 7% interest) [IDAC]*** | $0 | |
| ***Total Annual Cost [TAC] (DAC+IDAC)*** | **$269,553** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS FOR SCR (TACC+TAC)*** | **$1,316,535** | *Calculation* |
| Uncontrolled emissions tons/year | 36.1 | BP Estimation for BART |
| Emissions w/ULNB only tons/year | 28.5 | BART analysis |
| Emissions w/ULNB + SCR tons/year | 3.8 | control to 95% or 5 ppmv, whichever is greater |
| Reduction from ULNB Percent | 86.7 | *Calculation* |
| Overall Reduction from Uncontrolled Percent | 89.5 | *Calculation* |
| Total Emissions Reduction for SCR + ULNB tons/year | 32.3 | *Calculation* |
| ***Cost per ton Controlled*** ***$/ton*** | **$ 40,768** | *Calculation* |

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Section 4.2 Chapter 2: Selective Catalytic Reduction (October 2000)

Calculation assumes that the LNB installation and cost will not change as a result of the SCR installation. The SCR costs were adjusted to account for the lower post-LNB inlet NOx concentration resulting in needing less catalyst and less ammonia consumption.

# APPENDIX D

BP BART

Spray Tower Cost Effectiveness Calculation - Crude Charge Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $1,896,038 | Jacobs |
| b. Vessel Installed Cost | | $5,223,068 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $2,729,771 | Jacobs |
| d. Duct Installed Cost | | $1,011,435 | Jacobs |
| e. Cyclone Installed Cost | | $130,779 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $10,991,092 | *Calculation* |
| f. CEMS Installation | | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| i. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1.25 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $14,363,865 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | | $5,745,546 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $20,109,411 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades | | $2,500,000 | |
| J. Lost Production due to extended turnaround | | $84,000,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $106,609,411 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$10,063,174** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| K. Labor for operations (assumed none add'l for spray tower) | | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for spray tower) | | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | | $339,141 | Jacobs based on OAQPS |
| N. Utility costs | | | |
| a. Electricity (fan & pump) | | $234,410 | Jacobs |
| b. Sewer | | $31,261 | Jacobs |
| O. Caustic costs | | $78,153 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| P. Overhead (assumed none add'l for spray tower) | | $0 | Jacobs |
| Q. Administration (assumed none add'l for spray tower) | | $0 | Jacobs |
| R. Insurance (assumed none add'l for spray tower) | | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$682,965** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$10,746,140** | *Calculation* |
| Baseline emissions | tons/year | 87.8 | BP Estimation for BART |
| Emissions w/spray tower | tons/year | 4.4 | *Calculation* |
| Reduction from baseline | Percent | 95.0 | Jacobs |
| Total Emissions Reduction | tons/year | 83.4 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 128,907** | *Calculation* |

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BP BART

Spray Tower Cost Effectiveness Calculation - South Vacuum Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $915,942 | Jacobs |
| b. Vessel Installed Cost | | $2,949,040 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $1,445,926 | Jacobs |
| d. Duct Installed Cost | | $602,039 | Jacobs |
| e. Cyclone Installed Cost | | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $5,962,947 | *Calculation* |
| f. CEMS Installation | | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| i. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit factor (ease of retrofit) | | 1.1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $7,109,241 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | | $2,843,696 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $9,952,938 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Lost Production due to extended turnaround | | $8,000,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $17,952,938 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$1,694,630** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| K. Labor for operations (assumed none add'l for spray tower) | | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for spray tower) | | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | | $149,294 | Jacobs based on OAQPS |
| N. Utility costs | | | |
| a. Electricity (fan & pump) | | $81,651 | Jacobs |
| b. Sewer | | $13,250 | Jacobs |
| O. Caustic costs | | $33,124 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| P. Overhead (assumed none add'l for spray tower) | | $0 | Jacobs |
| Q. Administration (assumed none add'l for spray tower) | | $0 | Jacobs |
| R. Insurance (assumed none add'l for spray tower) | | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$277,319** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$1,971,949** | *Calculation* |
| Baseline emissions | tons/year | 33.7 | BP Estimation for BART |
| Emissions w/spray tower | tons/year | 1.7 | *Calculation* |
| Reduction from baseline | Percent | 95.0 | Jacobs |
| Total Emissions Reduction | tons/year | 32.0 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 61,590** | *Calculation* |

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BP BART

Spray Tower Cost Effectiveness Calculation - Naphtha HDS Charge Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $607,059 | Jacobs |
| b. Vessel Installed Cost | $2,080,238 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $971,380 | Jacobs |
| d. Duct Installed Cost | $534,906 | Jacobs |
| e. Cyclone Installed Cost | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $4,243,583 | *Calculation* |
| f. CEMS Installation | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | $0 | Jacobs |
| i. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $4,743,583 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $1,897,433 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $6,641,016 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| I. Production Loss (due to extended turnaround) | $2,500,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | $9,141,016 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$862,847** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for spray tower) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for spray tower) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $99,615 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $52,887 | Jacobs |
| b. Sewer | $6,029 | Jacobs |
| O. Caustic costs | $15,071 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for spray tower) | $0 | Jacobs |
| Q. Administration (assumed none add'l for spray tower) | $0 | Jacobs |
| R. Insurance (assumed none add'l for spray tower) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$173,602** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$1,036,449** | *Calculation* |
| Baseline emissions tons/year | 16.9 | BP Estimation for BART |
| Emissions w/spray tower tons/year | 0.8 | *Calculation* |
| Reduction from baseline Percent | 95.0 | Jacobs |
| Total Emissions Reduction tons/year | 16.1 | *Calculation* |
| ***Cost per ton Conrolled*** ***$/ton*** | **$ 64,471** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quaility Planning and Standards (OAQPS).

BP BART

Spray Tower Cost Effectiveness Calculation - Naphtha HDS Stripper Reboiler Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $443,322 | Jacobs |
| b. Vessel Installed Cost | $1,610,533 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $723,020 | Jacobs |
| d. Duct Installed Cost | $389,660 | Jacobs |
| e. Cyclone Installed Cost | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $3,216,536 | *Calculation* |
| f. CEMS Installation | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | $0 | Jacobs |
| i. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $3,716,536 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $1,486,614 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $5,203,150 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| I. Production Loss (due to extended turnaround) | $2,500,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | $7,703,150 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$727,123** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for spray tower) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for spray tower) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $78,047 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $29,789 | Jacobs |
| b. Sewer | $3,685 | Jacobs |
| O. Caustic costs | $9,213 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for spray tower) | $0 | Jacobs |
| Q. Administration (assumed none add'l for spray tower) | $0 | Jacobs |
| R. Insurance (assumed none add'l for spray tower) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$120,735** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$847,858** | *Calculation* |
| Baseline emissions tons/year | 10.2 | BP Estimation for BART |
| Emissions w/spray tower tons/year | 0.5 | *Calculation* |
| Reduction from baseline Percent | 95.0 | Jacobs |
| Total Emissions Reduction tons/year | 9.7 | *Calculation* |
| ***Cost per ton Conrolled*** ***$/ton*** | **$ 87,215** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quality Planning and Standards (OAQPS).

BP BART
Spray Tower Cost Effectiveness Calculation - #1 Reformer Heaters
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $1,845,680 | Jacobs |
| b. Vessel Installed Cost | | $5,765,296 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $3,039,067 | Jacobs |
| d. Duct Installed Cost | | $1,241,990 | Jacobs |
| e. Cyclone Installed Cost | | $156,397 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $12,048,430 | *Calculation* |
| f. CEMS Installation | | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| i. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit factor (ease of retrofit) | | 1.3 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $16,312,959 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | | $6,525,183 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $22,838,142 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $2,500,000 | Jacobs |
| I. Production Loss (due to extended turnaround) | | $9,600,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $34,938,142 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$3,297,913** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| K. Labor for operations (assumed none add'l for spray tower) | | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for spray tower) | | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | | $380,072 | Jacobs based on OAQPS |
| N. Utility costs | | | |
| a. Electricity (fan & pump) | | $312,930 | Jacobs |
| b. Sewer | | $40,346 | Jacobs |
| O. Caustic costs | | $100,864 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| P. Overhead (assumed none add'l for spray tower) | | $0 | Jacobs |
| Q. Administration (assumed none add'l for spray tower) | | $0 | Jacobs |
| R. Insurance (assumed none add'l for spray tower) | | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$834,212** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$4,132,125** | *Calculation* |
| Baseline emissions | tons/year | 113.3 | BP Estimation for BART |
| Emissions w/spray tower | tons/year | 5.7 | *Calculation* |
| Reduction from baseline | Percent | 95.0 | Jacobs |
| Total Emissions Reduction | tons/year | 107.6 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 38,407** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quaility Planning and Standards (OAQPS).

BP BART

Spray Tower Cost Effectiveness Calculation - Coker Charge Heater (#1 North)

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $824,778 | Jacobs |
| b. Vessel Installed Cost | | $2,829,055 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $1,379,532 | Jacobs |
| d. Duct Installed Cost | | $603,044 | Jacobs |
| e. Cyclone Installed Cost | | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $5,686,408 | *Calculation* |
| f. CEMS Installation | | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| i. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $6,186,408 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | | $2,474,563 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $8,660,972 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| I. Production Loss (due to extended turnaround) | | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $8,660,972 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$817,534** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| K. Labor for operations (assumed none add'l for spray tower) | | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for spray tower) | | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | | $129,915 | Jacobs based on OAQPS |
| N. Utility costs | | | |
| a. Electricity (fan & pump) | | $78,403 | Jacobs |
| b. Sewer | | $16,237 | Jacobs |
| O. Caustic costs | | $40,592 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| P. Overhead (assumed none add'l for spray tower) | | $0 | Jacobs |
| Q. Administration (assumed none add'l for spray tower) | | $0 | Jacobs |
| R. Insurance (assumed none add'l for spray tower) | | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$265,146** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$1,082,680** | *Calculation* |
| Baseline emissions | tons/year | 34.2 | BP Estimation for BART |
| Emissions w/spray tower | tons/year | 1.7 | *Calculation* |
| Reduction from baseline | Percent | 95.0 | Jacobs |
| Total Emissions Reduction | tons/year | 32.5 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 33,306** | *Calculation* |

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BP BART

Spray Tower Cost Effectiveness Calculation - Coker Charge Heater (#2 South)

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $824,778 | Jacobs |
| b. Vessel Installed Cost | $2,829,055 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $1,379,532 | Jacobs |
| d. Duct Installed Cost | $603,044 | Jacobs |
| e. Cyclone Installed Cost | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $5,686,408 | *Calculation* |
| f. CEMS Installation | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | $0 | Jacobs |
| i. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $6,186,408 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $2,474,563 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $8,660,972 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| I. Production Loss (due to extended turnaround) | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | $8,660,972 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$817,534** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for spray tower) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for spray tower) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $129,915 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $78,403 | Jacobs |
| b. Sewer | $16,237 | Jacobs |
| O. Caustic costs | $40,592 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for spray tower) | $0 | Jacobs |
| Q. Administration (assumed none add'l for spray tower) | $0 | Jacobs |
| R. Insurance (assumed none add'l for spray tower) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$265,146** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$1,082,680** | *Calculation* |
| Baseline emissions tons/year | 34.8 | BP Estimation for BART |
| Emissions w/spray tower tons/year | 1.7 | *Calculation* |
| Reduction from baseline Percent | 95.0 | Jacobs |
| Total Emissions Reduction tons/year | 33.1 | *Calculation* |
| ***Cost per ton Conrolled*** ***$/ton*** | **$ 32,733** | *Calculation* |

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BP BART

Spray Tower Cost Effectiveness Calculation - Diesel HDS Charge Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $362,840 | Jacobs |
| b. Vessel Installed Cost | $1,377,051 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $602,747 | Jacobs |
| d. Duct Installed Cost | $311,241 | Jacobs |
| e. Cyclone Installed Cost | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $2,703,878 | *Calculation* |
| f. CEMS Installation | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | $0 | Jacobs |
| i. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $3,203,878 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $1,281,551 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $4,485,429 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| I. Production Loss (due to extended turnaround) | $3,600,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | $8,085,429 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$763,207** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for spray tower) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for spray tower) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $67,281 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $20,317 | Jacobs |
| b. Sewer | $2,721 | Jacobs |
| O. Caustic costs | $6,803 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for spray tower) | $0 | Jacobs |
| Q. Administration (assumed none add'l for spray tower) | $0 | Jacobs |
| R. Insurance (assumed none add'l for spray tower) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$97,123** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$860,331** | *Calculation* |
| Baseline emissions tons/year | 5.4 | BP Estimation for BART |
| Emissions w/spray tower tons/year | 0.3 | *Calculation* |
| Reduction from baseline Percent | 95.0 | Jacobs |
| Total Emissions Reduction tons/year | 5.1 | *Calculation* |
| ***Cost per ton Conrolled*** ***$/ton*** | **$ 168,330** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quality Planning and Standards (OAQPS).

BP BART

Spray Tower Cost Effectiveness Calculation - Diesel HDS Stabilizer Reboiler

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $425,058 | Jacobs |
| b. Vessel Installed Cost | $1,548,994 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $691,083 | Jacobs |
| d. Duct Installed Cost | $379,739 | Jacobs |
| e. Cyclone Installed Cost | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $3,094,874 | *Calculation* |
| f. CEMS Installation | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | $0 | Jacobs |
| i. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $3,594,874 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $1,437,950 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $5,032,824 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| I. Production Loss (due to extended turnaround) | $3,600,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | $8,632,824 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$814,877** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for spray tower) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for spray tower) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $75,492 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $28,000 | Jacobs |
| b. Sewer | $3,418 | Jacobs |
| O. Caustic costs | $8,545 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for spray tower) | $0 | Jacobs |
| Q. Administration (assumed none add'l for spray tower) | $0 | Jacobs |
| R. Insurance (assumed none add'l for spray tower) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$115,456** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$930,333** | *Calculation* |
| Baseline emissions tons/year | 8.9 | BP Estimation for BART |
| Emissions w/spray tower tons/year | 0.4 | *Calculation* |
| Reduction from baseline Percent | 95.0 | Jacobs |
| Total Emissions Reduction tons/year | 8.5 | *Calculation* |
| ***Cost per ton Conrolled*** ***$/ton*** | **$ 109,737** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).

BP BART

Spray Tower Cost Effectiveness Calculation - Reforming Furnace #1 - (North H2 Plant)

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $1,196,137 | Jacobs |
| b. Vessel Installed Cost | $3,656,968 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $1,841,479 | Jacobs |
| d. Duct Installed Cost | $800,275 | Jacobs |
| e. Cyclone Installed Cost | $67,859 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $7,562,718 | *Calculation* |
| f. CEMS Installation | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | $0 | Jacobs |
| i. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit factor (ease of retrofit) | 1.3 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $10,481,533 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $4,192,613 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $14,674,146 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| I. Production Loss (due to extended turnaround) | $23,750,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | $38,424,146 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$3,626,968** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for spray tower) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for spray tower) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $220,112 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $133,053 | Jacobs |
| b. Sewer | $17,505 | Jacobs |
| O. Caustic costs | $43,764 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for spray tower) | $0 | Jacobs |
| Q. Administration (assumed none add'l for spray tower) | $0 | Jacobs |
| R. Insurance (assumed none add'l for spray tower) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$414,434** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$4,041,402** | *Calculation* |

| | | | |
|---|---|---|---|
| Baseline emissions | tons/year | 49.1 | BP Estimation for BART |
| Emissions w/spray tower | tons/year | 2.5 | *Calculation* |
| Reduction from baseline | Percent | 95.0 | Jacobs |
| Total Emissions Reduction | tons/year | 46.7 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 86,602** | *Calculation* |

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BP BART

Spray Tower Cost Effectiveness Calculation - Reforming Furnace #2 - (South H2 Plant)

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $1,182,092 | Jacobs |
| b. Vessel Installed Cost | $3,618,517 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $1,819,856 | Jacobs |
| d. Duct Installed Cost | $792,437 | Jacobs |
| e. Cyclone Installed Cost | $66,536 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $7,479,438 | *Calculation* |
| f. CEMS Installation | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | $0 | Jacobs |
| i. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit factor (ease of retrofit) | 1.3 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $10,373,270 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $4,149,308 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $14,522,578 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| I. Production Loss (due to extended turnaround) | $23,750,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | $38,272,578 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$3,612,661** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for spray tower) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for spray tower) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $217,839 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $130,459 | Jacobs |
| b. Sewer | $17,164 | Jacobs |
| O. Caustic costs | $42,911 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for spray tower) | $0 | Jacobs |
| Q. Administration (assumed none add'l for spray tower) | $0 | Jacobs |
| R. Insurance (assumed none add'l for spray tower) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$408,373** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$4,021,033** | *Calculation* |
| Baseline emissions tons/year | 48.2 | BP Estimation for BART |
| Emissions w/spray tower tons/year | 2.4 | *Calculation* |
| Reduction from baseline Percent | 95.0 | Jacobs |
| Total Emissions Reduction tons/year | 45.8 | *Calculation* |
| ***Cost per ton Conrolled*** ***$/ton*** | **$ 87,850** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).

BP BART

Spray Tower Cost Effectiveness Calculation - R-1 HC Reactor Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $536,599 | Jacobs |
| b. Vessel Installed Cost | $1,902,303 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $876,428 | Jacobs |
| d. Duct Installed Cost | $454,861 | Jacobs |
| e. Cyclone Installed Cost | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $3,820,191 | *Calculation* |
| f. CEMS Installation | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | $0 | Jacobs |
| i. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $4,320,191 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $1,728,076 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $6,048,267 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| I. Production Loss (due to extended turnaround) | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | $6,048,267 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$570,914** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for spray tower) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for spray tower) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $90,724 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $40,793 | Jacobs |
| b. Sewer | $5,079 | Jacobs |
| O. Caustic costs | $12,697 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for spray tower) | $0 | Jacobs |
| Q. Administration (assumed none add'l for spray tower) | $0 | Jacobs |
| R. Insurance (assumed none add'l for spray tower) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$149,293** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$720,207** | *Calculation* |
| Baseline emissions tons/year | 14.2 | BP Estimation for BART |
| Emissions w/spray tower tons/year | 0.7 | *Calculation* |
| Reduction from baseline Percent | 95.0 | Jacobs |
| Total Emissions Reduction tons/year | 13.5 | *Calculation* |
| ***Cost per ton Conrolled*** ***$/ton*** | **$ 53,238** | *Calculation* |

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BP BART

Spray Tower Cost Effectiveness Calculation - R-4 HC Reactor Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $350,668 | Jacobs |
| b. Vessel Installed Cost | $1,287,635 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $557,385 | Jacobs |
| d. Duct Installed Cost | $344,792 | Jacobs |
| e. Cyclone Installed Cost | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $2,590,479 | *Calculation* |
| f. CEMS Installation | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | $0 | Jacobs |
| i. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $3,090,479 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $1,236,192 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $4,326,670 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| I. Production Loss (due to extended turnaround) | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | $4,326,670 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$408,407** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for spray tower) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for spray tower) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $64,900 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $21,562 | Jacobs |
| b. Sewer | $2,389 | Jacobs |
| O. Caustic costs | $5,972 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for spray tower) | $0 | Jacobs |
| Q. Administration (assumed none add'l for spray tower) | $0 | Jacobs |
| R. Insurance (assumed none add'l for spray tower) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$94,822** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$503,230** | *Calculation* |
| Baseline emissions tons/year | 6.7 | BP Estimation for BART |
| Emissions w/spray tower tons/year | 0.3 | *Calculation* |
| Reduction from baseline Percent | 95.0 | Jacobs |
| Total Emissions Reduction tons/year | 6.4 | *Calculation* |
| ***Cost per ton Conrolled*** ***$/ton*** | **$ 79,040** | *Calculation* |

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BP BART

Spray Tower Cost Effectiveness Calculation - 1st Stage HC Fractionator Reboiler

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $833,240 | Jacobs |
| b. Vessel Installed Cost | $2,937,607 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $1,439,591 | Jacobs |
| d. Duct Installed Cost | $539,359 | Jacobs |
| e. Cyclone Installed Cost | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $5,799,798 | *Calculation* |
| f. CEMS Installation | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | $0 | Jacobs |
| i. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $6,299,798 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $2,519,919 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $8,819,717 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| I. Production Loss (due to extended turnaround) | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | $8,819,717 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$832,519** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for spray tower) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for spray tower) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $132,296 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $73,212 | Jacobs |
| b. Sewer | $11,613 | Jacobs |
| O. Caustic costs | $29,034 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for spray tower) | $0 | Jacobs |
| Q. Administration (assumed none add'l for spray tower) | $0 | Jacobs |
| R. Insurance (assumed none add'l for spray tower) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$246,155** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$1,078,674** | *Calculation* |
| Baseline emissions tons/year | 27.6 | BP Estimation for BART |
| Emissions w/spray tower tons/year | 1.4 | *Calculation* |
| Reduction from baseline Percent | 95.0 | Jacobs |
| Total Emissions Reduction tons/year | 26.2 | *Calculation* |
| ***Cost per ton Conrolled*** ***$/ton*** | **$ 41,119** | *Calculation* |

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BP BART

Spray Tower Cost Effectiveness Calculation - 2nd Stage HC Fractionator Reboiler

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $779,087 | Jacobs |
| b. Vessel Installed Cost | $2,776,652 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $1,350,608 | Jacobs |
| d. Duct Installed Cost | $502,948 | Jacobs |
| e. Cyclone Installed Cost | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $5,459,295 | *Calculation* |
| f. CEMS Installation | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | $0 | Jacobs |
| i. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $5,959,295 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $2,383,718 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $8,343,014 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| I. Production Loss (due to extended turnaround) | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | $8,343,014 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$787,521** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for spray tower) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for spray tower) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $125,145 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $64,879 | Jacobs |
| b. Sewer | $10,442 | Jacobs |
| O. Caustic costs | $26,105 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for spray tower) | $0 | Jacobs |
| Q. Administration (assumed none add'l for spray tower) | $0 | Jacobs |
| R. Insurance (assumed none add'l for spray tower) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$226,571** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$1,014,092** | *Calculation* |
| Baseline emissions tons/year | 23.1 | BP Estimation for BART |
| Emissions w/spray tower tons/year | 1.2 | *Calculation* |
| Reduction from baseline Percent | 95.0 | Jacobs |
| Total Emissions Reduction tons/year | 21.9 | *Calculation* |
| ***Cost per ton Conrolled*** ***$/ton*** | **$ 46,271** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quality Planning and Standards (OAQPS).

BP BART
Fuel Gas Conditioning Cost Effectiveness Calculation - Overall
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Equipment (Material & Labor) | $4,475,340 | BP FGC Team Appraise Estimate |
| b. Concrete (Material & Labor) | $222,900 | BP FGC Team Appraise Estimate |
| b. Civil (Material & Labor) | $690,100 | BP FGC Team Appraise Estimate |
| c. Steel (Material & Labor) | $761,400 | BP FGC Team Appraise Estimate |
| d. Fireproofing (Material & Labor) | $595,900 | BP FGC Team Appraise Estimate |
| e. Piping (Material & Labor) | $4,806,160 | BP FGC Team Appraise Estimate |
| f. Insulation (Material & Labor) | $627,800 | BP FGC Team Appraise Estimate |
| g. Instruments (Material & Labor) | $2,007,500 | BP FGC Team Appraise Estimate |
| h. Electrical (Material & Labor) | $231,660 | BP FGC Team Appraise Estimate |
| i. Conduit (Material & Labor) | $457,100 | BP FGC Team Appraise Estimate |
| j. Painting (Material & Labor) | $140,300 | BP FGC Team Appraise Estimate |
| k. Scaffolding (Material & Labor) | $1,482,100 | BP FGC Team Appraise Estimate |
| l. Firewatch/Holewatch (Material & Labor) | $650,300 | BP FGC Team Appraise Estimate |
| m. MTO Allowance (Material & Labor) | $2,008,000 | BP FGC Team Appraise Estimate |
| n. Freight | $428,000 | BP FGC Team Appraise Estimate |
| ***Total Direct Field Costs*** | $19,557,560 | *Calculation* |
| B. Direct Installation Costs | | |
| a. Construction Service Labor (included in craft billing rates) | $0 | BP FGC Team Appraise Estimate |
| b. Non-Productive (bus) time (5%) | $410,805 | BP FGC Team Appraise Estimate |
| c. Small Tools (included in craft billing rates) | $0 | BP FGC Team Appraise Estimate |
| d. Consumables (included in craft billing rates) | $0 | BP FGC Team Appraise Estimate |
| e. Non-Payroll Taxes & Insurance (included in craft billing rates) | $0 | BP FGC Team Appraise Estimate |
| f. Construction Equipment (included in craft billing rates) | $0 | BP FGC Team Appraise Estimate |
| g. Field Staff (included in craft billing rates) | $0 | BP FGC Team Appraise Estimate |
| h. OH & Profit (included in craft billing rates) | $0 | BP FGC Team Appraise Estimate |
| i. Premium on OT Work (11%) | $999,591 | BP FGC Team Appraise Estimate |
| j. Per Diem Allowance (6%) | $373,686 | BP FGC Team Appraise Estimate |
| k. Crane Cost | $200,000 | BP FGC Team Appraise Estimate |
| l. Safety Control (5%) | $410,905 | BP FGC Team Appraise Estimate |
| ***Total Direct Installation Costs*** | $2,394,987 | *Calculation* |
| ***Total Direct Costs*** | $21,952,960 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Detailed Design (16%) | $9,293,200 | BP FGC Team Appraise Estimate |
| b. License Fee | $100,000 | BP FGC Team Appraise Estimate |
| c. Proprietary Hardware | $800,000 | BP FGC Team Appraise Estimate |
| d. Engineering Fee | $130,000 | BP FGC Team Appraise Estimate |
| e. Client Costs (20%) | $6,250,000 | BP FGC Team Appraise Estimate |
| ***Total Indirect Costs [ICC]*** | $16,573,200 | *Calculation* |
| D. Project Contingency ([DCC + ICC]*0.4) | $15,755,680 | Jacobs - ROM ± 50% |
| E. Escalation | $0 | BP FGC Team Appraise Estimate |
| F. Catalyst | $75,000 | BP FGC Team Appraise Estimate |
| G. Substation | $10,000,000 | BP FGC Team Appraise Estimate |
| H. NHT Upgrades | $5,000,000 | BP FGC Team Appraise Estimate |
| I. Vaporizer in LEU | $5,000,000 | BP FGC Team Appraise Estimate |
| ***Total Project Cost (in 2006 dollars)*** | $70,590,225 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$6,663,218** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| J. Operating Cost (assumed 0.035 *installed cost) | $2,470,658 | Jacobs |
| K. Maintenance Labor and Costs (0.015*installed cost) | $1,058,853 | Jacobs based on OAQPS |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$3,529,511** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$10,192,729** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quality Planning and Standards (OAQPS).

| BART Emission Unit ID | Point ID | BART Source Point Discription | SO2 Reduction tpy | Total Project Cost $ | Total Operating Cost $ | Cost per ton $/ton |
|---|---|---|---|---|---|---|
| 1 | 10 | Crude Charge Heater | 78 | 12,048,319 | 602,416 | $22,282 |
| 34 | 12 | South Vacuum Heater | 30 | 4,627,358 | 231,368 | $22,282 |
| 3 | 22 | Naphtha HDS Charge Heater | 15 | 2,323,432 | 116,172 | $22,282 |
| 4 | 23 | Naphtha HDS Stripper Reboiler | 9 | 1,405,019 | 70,251 | $22,282 |
| 5 | 20 | #1 Reformer Heaters | 101 | 15,549,462 | 777,473 | $22,282 |
| 6 | 40 | Coker Charge Heater (#1 North) | 30 | 4,698,215 | 234,911 | $22,282 |
| 7 | 41 | Coker Charge Heater (#2 South) | 31 | 4,780,467 | 239,023 | $22,282 |
| 8 | 50 | Diesel HDS Charge Heater | 5 | 738,676 | 36,934 | $22,282 |
| 9 | 51 | Diesel HDS Stabilizer Reboiler | 8 | 1,225,282 | 61,264 | $22,282 |
| 10 | 60 | Reforming Furnace #1 - (North H2 Plant) | 44 | 6,744,530 | 337,226 | $22,282 |
| 11 | 61 | Reforming Furnace #2 - (South H2 Plant) | 43 | 6,615,207 | 330,760 | $22,282 |
| 12 | 32 | R-1 HC Reactor Heater | 13 | 1,955,190 | 97,760 | $22,282 |
| 13 | 33 | R-4 HC Reactor Heater | 6 | 920,167 | 46,008 | $22,282 |
| 14 | 30 | 1st Stage HC Fractionator Reboiler | 25 | 3,791,360 | 189,568 | $22,282 |
| 15 | 31 | 2nd Stage HC Fractionator Reboiler | 21 | 3,167,540 | 158,377 | $22,282 |
| | | **Sum** | 457 | | | |

BP BART

Fuel Gas Conditioning & Spray Tower Cost Effectiveness Calculation - Crude Charge Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $1,896,038 | Jacobs |
| b. Vessel Installed Cost | | $5,223,068 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $2,729,771 | Jacobs |
| d. Duct Installed Cost | | $1,011,435 | Jacobs |
| e. Cyclone Installed Cost | | $130,779 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $10,991,092 | *Calculation* |
| f. CEMS Installation | | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| i. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1.25 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $14,363,865 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| D. Project Contingency ([DCC + ICC]*0.4) | | $5,745,546 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $20,109,411 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $2,500,000 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $84,000,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $106,609,411 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $12,048,319 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$11,200,450** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for spray tower) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for spray tower) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $339,141 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $234,410 | Jacobs |
| b. Sewer | | $3,447 | Jacobs |
| M. Caustic costs | | $8,618 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for spray tower) | | $0 | Jacobs |
| O. Administration (assumed none add'l for spray tower) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for spray tower) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $602,416 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$1,188,032** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$12,388,483** | *Calculation* |
| Baseline emissions | tons/year | 87.8 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 9.7 | BART analysis |
| Emissions w/FGC + Spray Tower | tons/year | 0.48 | *Calculation* |
| Reduction from FGC | Percent | 95.0 | control to 95% |
| Total Emissions Reduction | tons/year | 87.3 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 141,960** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quaility Planning and Standards (OAQPS).

BP BART

Fuel Gas Conditioning & Spray Tower Cost Effectiveness Calculation - South Vacuum Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $915,942 | Jacobs |
| b. Vessel Installed Cost | | $2,949,040 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $1,445,926 | Jacobs |
| d. Duct Installed Cost | | $602,039 | Jacobs |
| e. Cyclone Installed Cost | | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $5,962,947 | *Calculation* |
| f. CEMS Installation | | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| i. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1.1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $7,109,241 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| D. Project Contingency ([DCC + ICC]*0.4) | | $2,843,696 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $9,952,938 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $8,000,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $17,952,938 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $4,627,358 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$2,131,420** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for spray tower) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for spray tower) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $149,294 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $81,651 | Jacobs |
| b. Sewer | | $1,461 | Jacobs |
| M. Caustic costs | | $3,653 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for spray tower) | | $0 | Jacobs |
| O. Administration (assumed none add'l for spray tower) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for spray tower) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $231,368 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$467,427** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$2,598,848** | *Calculation* |
| Baseline emissions | tons/year | 33.7 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 3.7 | BART analysis |
| Emissions w/FGC + Spray Tower | tons/year | 0.19 | *Calculation* |
| Reduction from FGC | Percent | 95.0 | control to 95% |
| Total Emissions Reduction | tons/year | 33.5 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 77,539** | *Calculation* |

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Office of Air Quaility Planning and Standards (OAQPS).

BP BART

Fuel Gas Conditioning & Spray Tower Cost Effectiveness Calculation - Naphtha HDS Charge Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $607,059 | Jacobs |
| b. Vessel Installed Cost | | $2,080,238 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $971,380 | Jacobs |
| d. Duct Installed Cost | | $534,906 | Jacobs |
| e. Cyclone Installed Cost | | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $4,243,583 | *Calculation* |
| f. CEMS Installation | | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| i. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $4,743,583 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| D. Project Contingency ([DCC + ICC]*0.4) | | $1,897,433 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $6,641,016 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $2,500,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $9,141,016 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $2,323,432 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$1,082,163** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for spray tower) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for spray tower) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $99,615 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $52,887 | Jacobs |
| b. Sewer | | $665 | Jacobs |
| M. Caustic costs | | $1,662 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for spray tower) | | $0 | Jacobs |
| O. Administration (assumed none add'l for spray tower) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for spray tower) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $116,172 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$271,000** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$1,353,163** | *Calculation* |
| Baseline emissions | tons/year | 16.9 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 1.9 | BART analysis |
| Emissions w/FGC + Spray Tower | tons/year | 0.09 | *Calculation* |
| Reduction from FGC | Percent | 95.0 | control to 95% |
| Total Emissions Reduction | tons/year | 16.8 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 80,407** | *Calculation* |

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Office of Air Quaility Planning and Standards (OAQPS).

BP BART

Fuel Gas Conditioning & Spray Tower Cost Effectiveness Calculation - Naphtha HDS Stripper Reboiler Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $443,322 | Jacobs |
| b. Vessel Installed Cost | | $1,610,533 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $723,020 | Jacobs |
| d. Duct Installed Cost | | $389,660 | Jacobs |
| e. Cyclone Installed Cost | | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $3,216,536 | *Calculation* |
| f. CEMS Installation | | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| i. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $3,716,536 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| D. Project Contingency ([DCC + ICC]*0.4) | | $1,486,614 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $5,203,150 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $2,500,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $7,703,150 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $1,405,019 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$859,747** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for spray tower) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for spray tower) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $78,047 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $29,789 | Jacobs |
| b. Sewer | | $406 | Jacobs |
| M. Caustic costs | | $1,016 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for spray tower) | | $0 | Jacobs |
| O. Administration (assumed none add'l for spray tower) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for spray tower) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $70,251 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$179,509** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$1,039,256** | *Calculation* |
| Baseline emissions | tons/year | 10.2 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 1.1 | BART analysis |
| Emissions w/FGC + Spray Tower | tons/year | 0.06 | *Calculation* |
| Reduction from FGC | Percent | 95.0 | control to 95% |
| Total Emissions Reduction | tons/year | 10.2 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 102,121** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quaility Planning and Standards (OAQPS).

BP BART

Fuel Gas Conditioning & Spray Tower Cost Effectiveness Calculation - #1 Reformer Heaters

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $1,845,680 | Jacobs |
| b. Vessel Installed Cost | | $5,765,296 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $3,039,067 | Jacobs |
| d. Duct Installed Cost | | $1,241,990 | Jacobs |
| e. Cyclone Installed Cost | | $156,397 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $12,048,430 | *Calculation* |
| f. CEMS Installation | | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| i. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1.3 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $16,312,959 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| D. Project Contingency ([DCC + ICC]*0.4) | | $6,525,183 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $22,838,142 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $2,500,000 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $9,600,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $34,938,142 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $15,549,462 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$4,765,673** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for spray tower) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for spray tower) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $380,072 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $312,930 | Jacobs |
| b. Sewer | | $4,449 | Jacobs |
| M. Caustic costs | | $11,123 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for spray tower) | | $0 | Jacobs |
| O. Administration (assumed none add'l for spray tower) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for spray tower) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $777,473 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$1,486,047** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$6,251,720** | *Calculation* |
| Baseline emissions | tons/year | 113.3 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 12.5 | BART analysis |
| Emissions w/FGC + Spray Tower | tons/year | 0.62 | *Calculation* |
| Reduction from FGC | Percent | 95.0 | control to 95% |
| Total Emissions Reduction | tons/year | 112.6 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 55,508** | *Calculation* |

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BP BART

Fuel Gas Conditioning & Spray Tower Cost Effectiveness Calculation - Coker Charge Heater (#1 North)

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $824,778 | Jacobs |
| b. Vessel Installed Cost | | $2,829,055 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $1,379,532 | Jacobs |
| d. Duct Installed Cost | | $603,044 | Jacobs |
| e. Cyclone Installed Cost | | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $5,686,408 | *Calculation* |
| f. CEMS Installation | | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| i. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $6,186,408 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| D. Project Contingency ([DCC + ICC]*0.4) | | $2,474,563 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $8,660,972 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $8,660,972 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $4,698,215 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$1,261,013** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for spray tower) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for spray tower) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $129,915 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $78,403 | Jacobs |
| b. Sewer | | $1,791 | Jacobs |
| M. Caustic costs | | $4,476 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for spray tower) | | $0 | Jacobs |
| O. Administration (assumed none add'l for spray tower) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for spray tower) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $234,911 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$449,495** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$1,710,508** | *Calculation* |
| Baseline emissions | tons/year | 34.2 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 3.8 | BART analysis |
| Emissions w/FGC + Spray Tower | tons/year | 0.19 | *Calculation* |
| Reduction from FGC | Percent | 95.0 | control to 95% |
| Total Emissions Reduction | tons/year | 34.0 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 50,265** | *Calculation* |

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BP BART

Fuel Gas Conditioning & Spray Tower Cost Effectiveness Calculation - Coker Charge Heater (#2 South)

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $824,778 | Jacobs |
| b. Vessel Installed Cost | | $2,829,055 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $1,379,532 | Jacobs |
| d. Duct Installed Cost | | $603,044 | Jacobs |
| e. Cyclone Installed Cost | | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $5,686,408 | *Calculation* |
| f. CEMS Installation | | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| i. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $6,186,408 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| D. Project Contingency ([DCC + ICC]*0.4) | | $2,474,563 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $8,660,972 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $8,660,972 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $4,780,467 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$1,268,777** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for spray tower) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for spray tower) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $129,915 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $78,403 | Jacobs |
| b. Sewer | | $1,791 | Jacobs |
| M. Caustic costs | | $4,476 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for spray tower) | | $0 | Jacobs |
| O. Administration (assumed none add'l for spray tower) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for spray tower) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $239,023 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$453,608** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$1,722,384** | *Calculation* |
| Baseline emissions | tons/year | 34.8 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 3.8 | BART analysis |
| Emissions w/FGC + Spray Tower | tons/year | 0.19 | *Calculation* |
| Reduction from FGC | Percent | 95.0 | control to 95% |
| Total Emissions Reduction | tons/year | 34.6 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 49,743** | *Calculation* |

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BP BART

Fuel Gas Conditioning & Spray Tower Cost Effectiveness Calculation - Diesel HDS Charge Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $362,840 | Jacobs |
| b. Vessel Installed Cost | | $1,377,051 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $602,747 | Jacobs |
| d. Duct Installed Cost | | $311,241 | Jacobs |
| e. Cyclone Installed Cost | | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $2,703,878 | *Calculation* |
| f. CEMS Installation | | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| i. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $3,203,878 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| D. Project Contingency ([DCC + ICC]*0.4) | | $1,281,551 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $4,485,429 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $3,600,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $8,085,429 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $738,676 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$832,933** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for spray tower) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for spray tower) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $67,281 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $20,317 | Jacobs |
| b. Sewer | | $300 | Jacobs |
| M. Caustic costs | | $750 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for spray tower) | | $0 | Jacobs |
| O. Administration (assumed none add'l for spray tower) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for spray tower) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $36,934 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$125,583** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$958,516** | *Calculation* |
| Baseline emissions | tons/year | 5.4 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 0.6 | BART analysis |
| Emissions w/FGC + Spray Tower | tons/year | 0.03 | *Calculation* |
| Reduction from FGC | Percent | 95.0 | control to 95% |
| Total Emissions Reduction | tons/year | 5.4 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 179,151** | *Calculation* |

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BP BART

Fuel Gas Conditioning & Spray Tower Cost Effectiveness Calculation - Diesel HDS Stabilizer Reboiler

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $425,058 | Jacobs |
| b. Vessel Installed Cost | | $1,548,994 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $691,083 | Jacobs |
| d. Duct Installed Cost | | $379,739 | Jacobs |
| e. Cyclone Installed Cost | | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $3,094,874 | *Calculation* |
| f. CEMS Installation | | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| i. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $3,594,874 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| D. Project Contingency ([DCC + ICC]*0.4) | | $1,437,950 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $5,032,824 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $3,600,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $8,632,824 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $1,225,282 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$930,535** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for spray tower) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for spray tower) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $75,492 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $28,000 | Jacobs |
| b. Sewer | | $377 | Jacobs |
| M. Caustic costs | | $942 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for spray tower) | | $0 | Jacobs |
| O. Administration (assumed none add'l for spray tower) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for spray tower) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $61,264 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$166,076** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$1,096,611** | *Calculation* |
| Baseline emissions | tons/year | 8.9 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 1.0 | BART analysis |
| Emissions w/FGC + Spray Tower | tons/year | 0.05 | *Calculation* |
| Reduction from FGC | Percent | 95.0 | control to 95% |
| Total Emissions Reduction | tons/year | 8.9 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 123,564** | *Calculation* |

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BP BART

Fuel Gas Conditioning & Spray Tower Cost Effectiveness Calculation - Reforming Furnace #1 - (North H2 Plant)

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $1,196,137 | Jacobs |
| b. Vessel Installed Cost | | $3,656,968 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $1,841,479 | Jacobs |
| d. Duct Installed Cost | | $800,275 | Jacobs |
| e. Cyclone Installed Cost | | $67,859 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $7,562,718 | *Calculation* |
| f. CEMS Installation | | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| i. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1.3 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $10,481,533 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| D. Project Contingency ([DCC + ICC]*0.4) | | $4,192,613 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $14,674,146 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $23,750,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $38,424,146 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $6,744,530 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$4,263,604** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for spray tower) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for spray tower) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $220,112 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $133,053 | Jacobs |
| b. Sewer | | $1,930 | Jacobs |
| M. Caustic costs | | $4,826 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for spray tower) | | $0 | Jacobs |
| O. Administration (assumed none add'l for spray tower) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for spray tower) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $337,226 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$697,148** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$4,960,751** | *Calculation* |
| Baseline emissions | tons/year | 49.1 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 5.4 | BART analysis |
| Emissions w/FGC + Spray Tower | tons/year | 0.27 | *Calculation* |
| Reduction from FGC | Percent | 95.0 | control to 95% |
| Total Emissions Reduction | tons/year | 48.9 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 101,548** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quaility Planning and Standards (OAQPS).

BP BART

Fuel Gas Conditioning & Spray Tower Cost Effectiveness Calculation - Reforming Furnace #2 - (South H2 Plant)

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $1,182,092 | Jacobs |
| b. Vessel Installed Cost | | $3,618,517 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $1,819,856 | Jacobs |
| d. Duct Installed Cost | | $792,437 | Jacobs |
| e. Cyclone Installed Cost | | $66,536 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $7,479,438 | *Calculation* |
| f. CEMS Installation | | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| i. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1.3 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $10,373,270 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| D. Project Contingency ([DCC + ICC]*0.4) | | $4,149,308 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $14,522,578 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $23,750,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $38,272,578 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $6,615,207 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$4,237,089** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for spray tower) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for spray tower) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $217,839 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $130,459 | Jacobs |
| b. Sewer | | $1,893 | Jacobs |
| M. Caustic costs | | $4,732 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for spray tower) | | $0 | Jacobs |
| O. Administration (assumed none add'l for spray tower) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for spray tower) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $330,760 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$685,683** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$4,922,772** | *Calculation* |
| Baseline emissions | tons/year | 48.2 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 5.3 | BART analysis |
| Emissions w/FGC + Spray Tower | tons/year | 0.27 | *Calculation* |
| Reduction from FGC | Percent | 95.0 | control to 95% |
| Total Emissions Reduction | tons/year | 47.9 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 102,740** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).

BP BART

Fuel Gas Conditioning & Spray Tower Cost Effectiveness Calculation - R-1 HC Reactor Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $536,599 | Jacobs |
| b. Vessel Installed Cost | | $1,902,303 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $876,428 | Jacobs |
| d. Duct Installed Cost | | $454,861 | Jacobs |
| e. Cyclone Installed Cost | | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $3,820,191 | *Calculation* |
| f. CEMS Installation | | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| i. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $4,320,191 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| D. Project Contingency ([DCC + ICC]*0.4) | | $1,728,076 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $6,048,267 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $6,048,267 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $1,955,190 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$755,470** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for spray tower) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for spray tower) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $90,724 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $40,793 | Jacobs |
| b. Sewer | | $560 | Jacobs |
| M. Caustic costs | | $1,400 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for spray tower) | | $0 | Jacobs |
| O. Administration (assumed none add'l for spray tower) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for spray tower) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $97,760 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$231,237** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$986,707** | *Calculation* |
| Baseline emissions | tons/year | 14.2 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 1.6 | BART analysis |
| Emissions w/FGC + Spray Tower | tons/year | 0.08 | *Calculation* |
| Reduction from FGC | Percent | 95.0 | control to 95% |
| Total Emissions Reduction | tons/year | 14.2 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 69,674** | *Calculation* |

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Office of Air Quaility Planning and Standards (OAQPS).

BP BART

Fuel Gas Conditioning & Spray Tower Cost Effectiveness Calculation - R-4 HC Reactor Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $350,668 | Jacobs |
| b. Vessel Installed Cost | | $1,287,635 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $557,385 | Jacobs |
| d. Duct Installed Cost | | $344,792 | Jacobs |
| e. Cyclone Installed Cost | | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $2,590,479 | *Calculation* |
| f. CEMS Installation | | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| i. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $3,090,479 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| D. Project Contingency ([DCC + ICC]*0.4) | | $1,236,192 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $4,326,670 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $4,326,670 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $920,167 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$495,264** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for spray tower) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for spray tower) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $64,900 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $21,562 | Jacobs |
| b. Sewer | | $263 | Jacobs |
| M. Caustic costs | | $659 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for spray tower) | | $0 | Jacobs |
| O. Administration (assumed none add'l for spray tower) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for spray tower) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $46,008 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$133,392** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$628,657** | *Calculation* |
| Baseline emissions | tons/year | 6.7 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 0.7 | BART analysis |
| Emissions w/FGC + Spray Tower | tons/year | 0.04 | *Calculation* |
| Reduction from FGC | Percent | 95.0 | control to 95% |
| Total Emissions Reduction | tons/year | 6.7 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 94,324** | *Calculation* |

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BP BART

Fuel Gas Conditioning & Spray Tower Cost Effectiveness Calculation - 1st Stage HC Fractionator Reboiler

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $833,240 | Jacobs |
| b. Vessel Installed Cost | | $2,937,607 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $1,439,591 | Jacobs |
| d. Duct Installed Cost | | $539,359 | Jacobs |
| e. Cyclone Installed Cost | | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $5,799,798 | *Calculation* |
| f. CEMS Installation | | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| i. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $6,299,798 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| D. Project Contingency ([DCC + ICC]*0.4) | | $2,519,919 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $8,819,717 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $8,819,717 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $3,791,360 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$1,190,396** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for spray tower) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for spray tower) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $132,296 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $73,212 | Jacobs |
| b. Sewer | | $1,281 | Jacobs |
| M. Caustic costs | | $3,202 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for spray tower) | | $0 | Jacobs |
| O. Administration (assumed none add'l for spray tower) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for spray tower) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $189,568 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$399,558** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$1,589,955** | *Calculation* |
| Baseline emissions | tons/year | 27.6 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 3.0 | BART analysis |
| Emissions w/FGC + Spray Tower | tons/year | 0.15 | *Calculation* |
| Reduction from FGC | Percent | 95.0 | control to 95% |
| Total Emissions Reduction | tons/year | 27.5 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 57,898** | *Calculation* |

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BP BART

Fuel Gas Conditioning & Spray Tower Cost Effectiveness Calculation - 2nd Stage HC Fractionator Reboiler

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $779,087 | Jacobs |
| b. Vessel Installed Cost | | $2,776,652 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $1,350,608 | Jacobs |
| d. Duct Installed Cost | | $502,948 | Jacobs |
| e. Cyclone Installed Cost | | $50,000 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $5,459,295 | *Calculation* |
| f. CEMS Installation | | $500,000 | Jacobs |
| g. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| i. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $5,959,295 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | *Calculation* |
| D. Project Contingency ([DCC + ICC]*0.4) | | $2,383,718 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $8,343,014 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $8,343,014 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $3,167,540 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$1,086,515** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for spray tower) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for spray tower) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $125,145 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $64,879 | Jacobs |
| b. Sewer | | $1,151 | Jacobs |
| M. Caustic costs | | $2,879 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for spray tower) | | $0 | Jacobs |
| O. Administration (assumed none add'l for spray tower) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for spray tower) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $158,377 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$352,431** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$1,438,946** | *Calculation* |
| Baseline emissions | tons/year | 23.1 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 2.5 | BART analysis |
| Emissions w/FGC + Spray Tower | tons/year | 0.13 | *Calculation* |
| Reduction from FGC | Percent | 95.0 | control to 95% |
| Total Emissions Reduction | tons/year | 22.9 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 62,719** | *Calculation* |

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# APPENDIX E

BP BART

Wet Electrostatic Precipitator Cost Effectiveness Calculation - Crude Charge Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $1,896,038 | Jacobs |
| b. Vessel Installed Cost | | $7,401,094 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $2,729,771 | Jacobs |
| d. Duct Installed Cost | | $1,011,435 | Jacobs |
| e. ESP Installed Cost | | $6,277,410 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $19,315,748 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| h. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1.25 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $24,144,685 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | | $9,657,874 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $33,802,559 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $2,500,000 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $84,000,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $120,302,559 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$11,355,711** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| K. Labor for operations (assumed none add'l for WESP) | | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for WESP) | | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | | $544,538 | Jacobs based on OAQPS |
| N. Utility costs | | | |
| a. Electricity (fan & pump) | | $296,273 | Jacobs |
| b. Sewer | | $8,143 | Jacobs |
| O. Caustic costs | | $20,357 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| P. Overhead (assumed none add'l for WESP) | | $0 | Jacobs |
| Q. Administration (assumed none add'l for WESP) | | $0 | Jacobs |
| R. Insurance (assumed none add'l for WESP) | | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$869,311** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$12,225,022** | *Calculation* |
| Baseline emissions | tons/year | 24.1 | BP Estimation for BART |
| Emissions w/WESP | tons/year | 2.4 | *Calculation* |
| Reduction from baseline | Percent | 90.0 | Jacobs |
| Total Emissions Reduction | tons/year | 21.7 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 563,011** | *Calculation* |

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BP BART

Wet Electrostatic Precipitator Cost Effectiveness Calculation - South Vacuum Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $915,942 | Jacobs |
| b. Vessel Installed Cost | | $4,231,605 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $1,445,926 | Jacobs |
| d. Duct Installed Cost | | $602,039 | Jacobs |
| e. WESP Installed Cost | | $2,176,775 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $9,372,288 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| h. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1.1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $10,309,516 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | | $4,123,807 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $14,433,323 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $8,000,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $22,433,323 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$2,117,547** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| K. Labor for operations (assumed none add'l for WESP) | | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for WESP) | | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | | $216,500 | Jacobs based on OAQPS |
| N. Utility costs | | | |
| a. Electricity (fan & pump) | | $103,104 | Jacobs |
| b. Sewer | | $2,824 | Jacobs |
| O. Caustic costs | | $7,059 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| P. Overhead (assumed none add'l for WESP) | | $0 | Jacobs |
| Q. Administration (assumed none add'l for WESP) | | $0 | Jacobs |
| R. Insurance (assumed none add'l for WESP) | | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$329,486** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$2,447,033** | *Calculation* |
| Baseline emissions | tons/year | 7.6 | BP Estimation for BART |
| Emissions w/WESP | tons/year | 0.8 | *Calculation* |
| Reduction from baseline | Percent | 90.0 | Jacobs |
| Total Emissions Reduction | tons/year | 6.8 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 358,643** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).

BP BART

Wet Electrostatic Precipitator Cost Effectiveness Calculation - Naphtha HDS Charge Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $607,059 | Jacobs |
| b. Vessel Installed Cost | $3,000,932 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $971,380 | Jacobs |
| d. Duct Installed Cost | $534,906 | Jacobs |
| e. WESP Installed Cost | $1,121,722 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $6,235,999 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | $0 | Jacobs |
| h. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $6,235,999 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $2,494,400 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $8,730,398 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | $2,500,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | $11,230,398 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$1,060,070** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for WESP) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for WESP) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $130,956 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $63,941 | Jacobs |
| b. Sewer | $1,455 | Jacobs |
| O. Caustic costs | $3,638 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for WESP) | $0 | Jacobs |
| Q. Administration (assumed none add'l for WESP) | $0 | Jacobs |
| R. Insurance (assumed none add'l for WESP) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$199,990** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$1,260,060** | *Calculation* |

| | | | |
|---|---|---|---|
| Baseline emissions | tons/year | 4.3 | BP Estimation for BART |
| Emissions w/WESP | tons/year | 0.4 | *Calculation* |
| Reduction from baseline | Percent | 90.0 | Jacobs |
| Total Emissions Reduction | tons/year | 3.9 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 324,753** | *Calculation* |

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BP BART

Wet Electrostatic Precipitator Cost Effectiveness Calculation - Naphtha HDS Stripper Reboiler Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $443,322 | Jacobs |
| b. Vessel Installed Cost | | $2,330,397 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $723,020 | Jacobs |
| d. Duct Installed Cost | | $389,660 | Jacobs |
| e. WESP Installed Cost | | $685,732 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $4,572,131 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| h. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $4,572,131 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | | $1,828,852 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $6,400,983 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $2,500,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $8,900,983 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$840,190** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| K. Labor for operations (assumed none add'l for WESP) | | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for WESP) | | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | | $96,015 | Jacobs based on OAQPS |
| N. Utility costs | | | |
| a. Electricity (fan & pump) | | $36,547 | Jacobs |
| b. Sewer | | $889 | Jacobs |
| O. Caustic costs | | $2,224 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| P. Overhead (assumed none add'l for WESP) | | $0 | Jacobs |
| Q. Administration (assumed none add'l for WESP) | | $0 | Jacobs |
| R. Insurance (assumed none add'l for WESP) | | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$135,674** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$975,864** | *Calculation* |
| Baseline emissions | tons/year | 2.6 | BP Estimation for BART |
| Emissions w/WESP | tons/year | 0.3 | *Calculation* |
| Reduction from baseline | Percent | 90.0 | Jacobs |
| Total Emissions Reduction | tons/year | 2.3 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 415,910** | *Calculation* |

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BP BART

Wet Electrostatic Precipitator Cost Effectiveness Calculation - #1 Reformer Heaters

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $1,845,680 | Jacobs |
| b. Vessel Installed Cost | $8,147,111 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $3,039,067 | Jacobs |
| d. Duct Installed Cost | $1,241,990 | Jacobs |
| e. WESP Installed Cost | $7,507,071 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $21,780,919 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | $0 | Jacobs |
| h. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | 1.3 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $28,315,194 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $11,326,078 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $39,641,272 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $2,500,000 | Jacobs |
| J. Production Loss (due to extended turnaround) | $9,600,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | $51,741,272 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$4,884,010** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for WESP) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for WESP) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $632,119 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $386,912 | Jacobs |
| b. Sewer | $9,738 | Jacobs |
| O. Caustic costs | $24,344 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for WESP) | $0 | Jacobs |
| Q. Administration (assumed none add'l for WESP) | $0 | Jacobs |
| R. Insurance (assumed none add'l for WESP) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$1,053,113** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$5,937,123** | *Calculation* |

| | | | |
|---|---|---|---|
| Baseline emissions | tons/year | 28.9 | BP Estimation for BART |
| Emissions w/WESP | tons/year | 2.9 | *Calculation* |
| Reduction from baseline | Percent | 90.0 | Jacobs |
| Total Emissions Reduction | tons/year | 26.0 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 228,640** | *Calculation* |

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BP BART

Wet Electrostatic Precipitator Cost Effectiveness Calculation - Coker Charge Heater (#1 North)

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $824,778 | Jacobs |
| b. Vessel Installed Cost | $4,062,352 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $1,379,532 | Jacobs |
| d. Duct Installed Cost | $603,044 | Jacobs |
| e. WESP Installed Cost | $2,012,750 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $8,882,455 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | $0 | Jacobs |
| h. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $8,882,455 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $3,552,982 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $12,435,438 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | $12,435,438 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$1,173,817** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for WESP) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for WESP) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $186,532 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $98,239 | Jacobs |
| b. Sewer | $2,611 | Jacobs |
| O. Caustic costs | $6,527 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for WESP) | $0 | Jacobs |
| Q. Administration (assumed none add'l for WESP) | $0 | Jacobs |
| R. Insurance (assumed none add'l for WESP) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$293,908** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$1,467,725** | *Calculation* |

| | | | |
|---|---|---|---|
| Baseline emissions | tons/year | 5.8 | BP Estimation for BART |
| Emissions w/WESP | tons/year | 0.6 | *Calculation* |
| Reduction from baseline | Percent | 90.0 | Jacobs |
| Total Emissions Reduction | tons/year | 5.2 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 280,792** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).

BP BART

Wet Electrostatic Precipitator Cost Effectiveness Calculation - Coker Charge Heater (#2 South)

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $824,778 | Jacobs |
| b. Vessel Installed Cost | $4,062,352 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $1,379,532 | Jacobs |
| d. Duct Installed Cost | $603,044 | Jacobs |
| e. WESP Installed Cost | $2,012,750 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $8,882,455 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | $0 | Jacobs |
| h. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $8,882,455 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $3,552,982 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $12,435,438 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | $12,435,438 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$1,173,817** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for WESP) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for WESP) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $186,532 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $98,239 | Jacobs |
| b. Sewer | $2,611 | Jacobs |
| O. Caustic costs | $6,527 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for WESP) | $0 | Jacobs |
| Q. Administration (assumed none add'l for WESP) | $0 | Jacobs |
| R. Insurance (assumed none add'l for WESP) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$293,908** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$1,467,725** | *Calculation* |

| | | | |
|---|---|---|---|
| Baseline emissions | tons/year | 5.9 | BP Estimation for BART |
| Emissions w/WESP | tons/year | 0.6 | *Calculation* |
| Reduction from baseline | Percent | 90.0 | Jacobs |
| Total Emissions Reduction | tons/year | 5.3 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 275,961** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).

BP BART

Wet Electrostatic Precipitator Cost Effectiveness Calculation - Diesel HDS Charge Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $362,840 | Jacobs |
| b. Vessel Installed Cost | $1,995,641 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $602,747 | Jacobs |
| d. Duct Installed Cost | $311,241 | Jacobs |
| e. WESP Installed Cost | $506,362 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $3,778,831 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | $0 | Jacobs |
| h. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $3,778,831 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $1,511,532 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $5,290,363 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | $3,600,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | $8,890,363 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$839,187** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for WESP) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for WESP) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $79,355 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $25,307 | Jacobs |
| b. Sewer | $657 | Jacobs |
| O. Caustic costs | $1,642 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for WESP) | $0 | Jacobs |
| Q. Administration (assumed none add'l for WESP) | $0 | Jacobs |
| R. Insurance (assumed none add'l for WESP) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$106,962** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$946,149** | *Calculation* |

| | | | |
|---|---|---|---|
| Baseline emissions | tons/year | 1.4 | BP Estimation for BART |
| Emissions w/WESP | tons/year | 0.1 | *Calculation* |
| Reduction from baseline | Percent | 90.0 | Jacobs |
| Total Emissions Reduction | tons/year | 1.2 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 767,004** | *Calculation* |

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BP BART

Wet Electrostatic Precipitator Cost Effectiveness Calculation - Diesel HDS Stabilizer Reboiler

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $425,058 | Jacobs |
| b. Vessel Installed Cost | | $2,242,260 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $691,083 | Jacobs |
| d. Duct Installed Cost | | $379,739 | Jacobs |
| e. WESP Installed Cost | | $635,995 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $4,374,135 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| h. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $4,374,135 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | | $1,749,654 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $6,123,789 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $3,600,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $9,723,789 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$917,857** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| K. Labor for operations (assumed none add'l for WESP) | | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for WESP) | | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | | $91,857 | Jacobs based on OAQPS |
| N. Utility costs | | | |
| a. Electricity (fan & pump) | | $34,268 | Jacobs |
| b. Sewer | | $825 | Jacobs |
| O. Caustic costs | | $2,062 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| P. Overhead (assumed none add'l for WESP) | | $0 | Jacobs |
| Q. Administration (assumed none add'l for WESP) | | $0 | Jacobs |
| R. Insurance (assumed none add'l for WESP) | | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$129,012** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$1,046,869** | *Calculation* |
| Baseline emissions | tons/year | 2.3 | BP Estimation for BART |
| Emissions w/WESP | tons/year | 0.2 | *Calculation* |
| Reduction from baseline | Percent | 90.0 | Jacobs |
| Total Emissions Reduction | tons/year | 2.0 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 511,621** | *Calculation* |

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BP BART

Wet Electrostatic Precipitator Cost Effectiveness Calculation - Reforming Furnace #1 - (North H2 Plant)

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $1,196,137 | Jacobs |
| b. Vessel Installed Cost | $5,225,874 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $1,841,479 | Jacobs |
| d. Duct Installed Cost | $800,275 | Jacobs |
| e. WESP Installed Cost | $3,257,227 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $12,320,991 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | $0 | Jacobs |
| h. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | 1.3 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $16,017,288 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $6,406,915 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $22,424,203 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | $23,750,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | $46,174,203 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$4,358,518** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for WESP) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for WESP) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $336,363 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $165,153 | Jacobs |
| b. Sewer | $4,225 | Jacobs |
| O. Caustic costs | $10,563 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for WESP) | $0 | Jacobs |
| Q. Administration (assumed none add'l for WESP) | $0 | Jacobs |
| R. Insurance (assumed none add'l for WESP) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$516,303** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$4,874,821** | *Calculation* |

| | | | |
|---|---|---|---|
| Baseline emissions | tons/year | 12.5 | BP Estimation for BART |
| Emissions w/WESP | tons/year | 1.3 | *Calculation* |
| Reduction from baseline | Percent | 90.0 | Jacobs |
| Total Emissions Reduction | tons/year | 11.3 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 432,812** | *Calculation* |

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BP BART

Wet Electrostatic Precipitator Cost Effectiveness Calculation - Reforming Furnace #2 - (South H2 Plant)

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $1,182,092 | Jacobs |
| b. Vessel Installed Cost | $5,172,056 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $1,819,856 | Jacobs |
| d. Duct Installed Cost | $792,437 | Jacobs |
| e. WESP Installed Cost | $3,193,733 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $12,160,174 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | $0 | Jacobs |
| h. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | 1.3 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $15,808,226 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $6,323,290 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $22,131,516 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | $23,750,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | $45,881,516 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$4,330,891** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for WESP) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for WESP) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $331,973 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $161,933 | Jacobs |
| b. Sewer | $4,143 | Jacobs |
| O. Caustic costs | $10,357 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for WESP) | $0 | Jacobs |
| Q. Administration (assumed none add'l for WESP) | $0 | Jacobs |
| R. Insurance (assumed none add'l for WESP) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$508,405** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$4,839,296** | *Calculation* |

| | | | |
|---|---|---|---|
| Baseline emissions | tons/year | 12.3 | BP Estimation for BART |
| Emissions w/WESP | tons/year | 1.2 | *Calculation* |
| Reduction from baseline | Percent | 90.0 | Jacobs |
| Total Emissions Reduction | tons/year | 11.0 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 438,057** | *Calculation* |

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BP BART

Wet Electrostatic Precipitator Cost Effectiveness Calculation - R-1 HC Reactor Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $536,599 | Jacobs |
| b. Vessel Installed Cost | $2,747,364 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $876,428 | Jacobs |
| d. Duct Installed Cost | $454,861 | Jacobs |
| e. WESP Installed Cost | $944,998 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $5,560,250 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | $0 | Jacobs |
| h. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $5,560,250 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $2,224,100 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $7,784,350 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | $7,784,350 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$734,788** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for WESP) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for WESP) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $116,765 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $50,106 | Jacobs |
| b. Sewer | $1,226 | Jacobs |
| O. Caustic costs | $3,064 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for WESP) | $0 | Jacobs |
| Q. Administration (assumed none add'l for WESP) | $0 | Jacobs |
| R. Insurance (assumed none add'l for WESP) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$171,162** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$905,949** | *Calculation* |

| | | | |
|---|---|---|---|
| Baseline emissions | tons/year | 3.6 | BP Estimation for BART |
| Emissions w/WESP | tons/year | 0.4 | *Calculation* |
| Reduction from baseline | Percent | 90.0 | Jacobs |
| Total Emissions Reduction | tons/year | 3.3 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 277,464** | *Calculation* |

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BP BART

Wet Electrostatic Precipitator Cost Effectiveness Calculation - R-4 HC Reactor Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $350,668 | Jacobs |
| b. Vessel Installed Cost | | $1,867,180 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $557,385 | Jacobs |
| d. Duct Installed Cost | | $344,792 | Jacobs |
| e. WESP Installed Cost | | $444,456 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $3,564,480 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| h. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $3,564,480 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | | $1,425,792 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $4,990,271 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $4,990,271 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$471,046** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| K. Labor for operations (assumed none add'l for WESP) | | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for WESP) | | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | | $74,854 | Jacobs based on OAQPS |
| N. Utility costs | | | |
| a. Electricity (fan & pump) | | $25,942 | Jacobs |
| b. Sewer | | $577 | Jacobs |
| O. Caustic costs | | $1,441 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| P. Overhead (assumed none add'l for WESP) | | $0 | Jacobs |
| Q. Administration (assumed none add'l for WESP) | | $0 | Jacobs |
| R. Insurance (assumed none add'l for WESP) | | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$102,814** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$573,860** | *Calculation* |
| Baseline emissions | tons/year | 1.7 | BP Estimation for BART |
| Emissions w/WESP | tons/year | 0.2 | *Calculation* |
| Reduction from baseline | Percent | 90.0 | Jacobs |
| Total Emissions Reduction | tons/year | 1.5 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 373,449** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).

BP BART

Wet Electrostatic Precipitator Cost Effectiveness Calculation - 1st Stage HC Fractionator Reboiler

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $833,240 | Jacobs |
| b. Vessel Installed Cost | | $4,215,488 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $1,439,591 | Jacobs |
| d. Duct Installed Cost | | $539,359 | Jacobs |
| e. WESP Installed Cost | | $2,160,902 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $9,188,581 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| h. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $9,188,581 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | | $3,675,432 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $12,864,013 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $12,864,013 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$1,214,272** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| K. Labor for operations (assumed none add'l for WESP) | | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for WESP) | | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | | $192,960 | Jacobs based on OAQPS |
| N. Utility costs | | | |
| a. Electricity (fan & pump) | | $94,508 | Jacobs |
| b. Sewer | | $2,803 | Jacobs |
| O. Caustic costs | | $7,007 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| P. Overhead (assumed none add'l for WESP) | | $0 | Jacobs |
| Q. Administration (assumed none add'l for WESP) | | $0 | Jacobs |
| R. Insurance (assumed none add'l for WESP) | | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$297,279** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$1,511,550** | *Calculation* |
| Baseline emissions | tons/year | 7.0 | BP Estimation for BART |
| Emissions w/WESP | tons/year | 0.7 | *Calculation* |
| Reduction from baseline | Percent | 90.0 | Jacobs |
| Total Emissions Reduction | tons/year | 6.3 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 238,737** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).

BP BART

Wet Electrostatic Precipitator Cost Effectiveness Calculation - 2nd Stage HC Fractionator Reboiler

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $779,087 | Jacobs |
| b. Vessel Installed Cost | | $3,988,363 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $1,350,608 | Jacobs |
| d. Duct Installed Cost | | $502,948 | Jacobs |
| e. WESP Installed Cost | | $1,942,907 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $8,563,913 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| h. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $8,563,913 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | | $3,425,565 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $11,989,478 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $11,989,478 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$1,131,722** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| K. Labor for operations (assumed none add'l for WESP) | | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for WESP) | | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | | $179,842 | Jacobs based on OAQPS |
| N. Utility costs | | | |
| a. Electricity (fan & pump) | | $84,026 | Jacobs |
| b. Sewer | | $2,520 | Jacobs |
| O. Caustic costs | | $6,301 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| P. Overhead (assumed none add'l for WESP) | | $0 | Jacobs |
| Q. Administration (assumed none add'l for WESP) | | $0 | Jacobs |
| R. Insurance (assumed none add'l for WESP) | | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$272,689** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$1,404,411** | *Calculation* |
| Baseline emissions | tons/year | 5.9 | BP Estimation for BART |
| Emissions w/WESP | tons/year | 0.6 | *Calculation* |
| Reduction from baseline | Percent | 90.0 | Jacobs |
| Total Emissions Reduction | tons/year | 5.3 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 265,500** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).

BP BART
Fuel Gas Conditioning Cost Effectiveness Calculation - Overall
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Equipment (Material & Labor) | $4,475,340 | BP FGC Team Appraise Estimate |
| b. Concrete (Material & Labor) | $222,900 | BP FGC Team Appraise Estimate |
| b. Civil (Material & Labor) | $690,100 | BP FGC Team Appraise Estimate |
| c. Steel (Material & Labor) | $761,400 | BP FGC Team Appraise Estimate |
| d. Fireproofing (Material & Labor) | $595,900 | BP FGC Team Appraise Estimate |
| e. Piping (Material & Labor) | $4,806,160 | BP FGC Team Appraise Estimate |
| f. Insulation (Material & Labor) | $627,800 | BP FGC Team Appraise Estimate |
| g. Instruments (Material & Labor) | $2,007,500 | BP FGC Team Appraise Estimate |
| h. Electrical (Material & Labor) | $231,660 | BP FGC Team Appraise Estimate |
| i. Conduit (Material & Labor) | $457,100 | BP FGC Team Appraise Estimate |
| j. Painting (Material & Labor) | $140,300 | BP FGC Team Appraise Estimate |
| k. Scaffolding (Material & Labor) | $1,482,100 | BP FGC Team Appraise Estimate |
| l. Firewatch/Holewatch (Material & Labor) | $650,300 | BP FGC Team Appraise Estimate |
| m. MTO Allowance (Material & Labor) | $2,008,000 | BP FGC Team Appraise Estimate |
| n. Freight | $428,000 | BP FGC Team Appraise Estimate |
| ***Total Direct Field Costs*** | $19,557,560 | *Calculation* |
| B. Direct Installation Costs | | |
| a. Construction Service Labor (included in craft billing rates) | $0 | BP FGC Team Appraise Estimate |
| b. Non-Productive (bus) time (5%) | $410,805 | BP FGC Team Appraise Estimate |
| c. Small Tools (included in craft billing rates) | $0 | BP FGC Team Appraise Estimate |
| d. Consumables (included in craft billing rates) | $0 | BP FGC Team Appraise Estimate |
| e. Non-Payroll Taxes & Insurance (included in craft billing rates) | $0 | BP FGC Team Appraise Estimate |
| f. Construction Equipment (included in craft billing rates) | $0 | BP FGC Team Appraise Estimate |
| g. Field Staff (included in craft billing rates) | $0 | BP FGC Team Appraise Estimate |
| h. OH & Profit (included in craft billing rates) | $0 | BP FGC Team Appraise Estimate |
| i. Premium on OT Work (11%) | $999,591 | BP FGC Team Appraise Estimate |
| j. Per Diem Allowance (6%) | $373,686 | BP FGC Team Appraise Estimate |
| k. Crane Cost | $200,000 | BP FGC Team Appraise Estimate |
| l. Safety Control (5%) | $410,905 | BP FGC Team Appraise Estimate |
| ***Total Direct Installation Costs*** | $2,394,987 | *Calculation* |
| ***Total Direct Costs*** | $21,952,960 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Detailed Design (16%) | $9,293,200 | BP FGC Team Appraise Estimate |
| b. License Fee | $100,000 | BP FGC Team Appraise Estimate |
| c. Proprietary Hardware | $800,000 | BP FGC Team Appraise Estimate |
| d. Engineering Fee | $130,000 | BP FGC Team Appraise Estimate |
| e. Client Costs (20%) | $6,250,000 | BP FGC Team Appraise Estimate |
| ***Total Indirect Costs [ICC]*** | $16,573,200 | *Calculation* |
| D. Project Contingency ([DCC + ICC]*0.4) | $15,755,680 | Jacobs - ROM ± 50% |
| E. Escalation | $0 | BP FGC Team Appraise Estimate |
| F. Catalyst | $75,000 | BP FGC Team Appraise Estimate |
| G. Substation | $10,000,000 | BP FGC Team Appraise Estimate |
| H. NHT Upgrades | $5,000,000 | BP FGC Team Appraise Estimate |
| I. Vaporizer in LEU | $5,000,000 | BP FGC Team Appraise Estimate |
| ***Total Project Cost (in 2006 dollars)*** | $70,590,225 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$6,663,218** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| J. Operating Cost (assumed 0.035 *installed cost) | $2,470,658 | Jacobs |
| K. Maintenance Labor and Costs (0.015*installed cost) | $1,058,853 | Jacobs based on OAQPS |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$3,529,511** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$10,192,729** | *Calculation* |

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| BART Emission Unit ID | Point ID | BART Source Point Discription | SO2 Reduction tpy | Total Project Cost $ | Total Operating Cost $ | Cost per ton $/ton |
|---|---|---|---|---|---|---|
| 1 | 10 | Crude Charge Heater | 6 | 13,529,778 | 676,489 | $323,896 |
| 34 | 12 | South Vacuum Heater | 2 | 4,251,434 | 212,572 | $323,896 |
| 3 | 22 | Naphtha HDS Charge Heater | 1 | 2,417,661 | 120,883 | $323,896 |
| 4 | 23 | Naphtha HDS Stripper Reboiler | 1 | 1,462,001 | 73,100 | $323,896 |
| 5 | 20 | #1 Reformer Heaters | 7 | 16,180,082 | 809,004 | $323,896 |
| 6 | 40 | Coker Charge Heater (#1 North) | 1 | 3,257,000 | 162,850 | $323,896 |
| 7 | 41 | Coker Charge Heater (#2 South) | 1 | 3,314,020 | 165,701 | $323,896 |
| 8 | 50 | Diesel HDS Charge Heater | 0 | 768,634 | 38,432 | $323,896 |
| 9 | 51 | Diesel HDS Stabilizer Reboiler | 1 | 1,274,974 | 63,749 | $323,896 |
| 10 | 60 | Reforming Furnace #1 - (North H2 Plant) | 3 | 7,018,059 | 350,903 | $323,896 |
| 11 | 61 | Reforming Furnace #2 - (South H2 Plant) | 3 | 6,883,491 | 344,175 | $323,896 |
| 12 | 32 | R-1 HC Reactor Heater | 1 | 2,034,484 | 101,724 | $323,896 |
| 13 | 33 | R-4 HC Reactor Heater | 0 | 957,485 | 47,874 | $323,896 |
| 14 | 30 | 1st Stage HC Fractionator Reboiler | 2 | 3,945,121 | 197,256 | $323,896 |
| 15 | 31 | 2nd Stage HC Fractionator Reboiler | 1 | 3,296,002 | 164,800 | $323,896 |
| | | **Sum** | 31 | | | |

BP BART

Fuel Gas Conditioning & Wet Electrostatic Precipitator Cost Effectiveness Calculation - Crude Charge Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $1,896,038 | Jacobs |
| b. Vessel Installed Cost | | $7,401,094 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $2,729,771 | Jacobs |
| d. Duct Installed Cost | | $1,011,435 | Jacobs |
| e. WESP Installed Cost | | $6,277,410 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $19,315,748 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| h. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1.25 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $24,144,685 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | | $9,657,874 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $33,802,559 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $2,500,000 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $84,000,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $120,302,559 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $13,529,778 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$12,632,826** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for WESP) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for WESP) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $544,538 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $296,273 | Jacobs |
| b. Sewer | | $6,107 | Jacobs |
| M. Caustic costs | | $15,267 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for WESP) | | $0 | Jacobs |
| O. Administration (assumed none add'l for WESP) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for WESP) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $676,489 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$1,538,675** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$14,171,501** | *Calculation* |
| Baseline emissions | tons/year | 24.1 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 18.1 | BART analysis |
| Emissions w/FGC + WESP | tons/year | 1.81 | *Calculation* |
| Reduction due to WESP | Percent | 90.0 | control to 90% |
| Total Emissions Reduction | tons/year | 22.3 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 635,014** | *Calculation* |

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Office of Air Quality Planning and Standards (OAQPS).

BP BART

Fuel Gas Conditioning & Wet Electrostatic Precipitator Cost Effectiveness Calculation - South Vacuum Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $915,942 | Jacobs |
| b. Vessel Installed Cost | | $4,231,605 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $1,445,926 | Jacobs |
| d. Duct Installed Cost | | $602,039 | Jacobs |
| e. WESP Installed Cost | | $2,176,775 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $9,372,288 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| h. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1.1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $10,309,516 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | | $4,123,807 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $14,433,323 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $8,000,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $22,433,323 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $4,251,434 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$2,518,852** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for WESP) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for WESP) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $216,500 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $103,104 | Jacobs |
| b. Sewer | | $2,118 | Jacobs |
| M. Caustic costs | | $5,294 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for WESP) | | $0 | Jacobs |
| O. Administration (assumed none add'l for WESP) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for WESP) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $212,572 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$539,587** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$3,058,439** | *Calculation* |
| Baseline emissions | tons/year | 7.581 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 5.686 | BART analysis |
| Emissions w/FGC + WESP | tons/year | 0.57 | *Calculation* |
| Reduction due to WESP | Percent | 90.0 | control to 90% |
| Total Emissions Reduction | tons/year | 7.0 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 436,137** | *Calculation* |

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BP BART

Fuel Gas Conditioning & Wet Electrostatic Precipitator Cost Effectiveness Calculation - Naphtha HDS Charge Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $607,059 | Jacobs |
| b. Vessel Installed Cost | | $3,000,932 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $971,380 | Jacobs |
| d. Duct Installed Cost | | $534,906 | Jacobs |
| e. WESP Installed Cost | | $1,121,722 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $6,235,999 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| h. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $6,235,999 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | | $2,494,400 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $8,730,398 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $2,500,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $11,230,398 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $2,417,661 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$1,288,280** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for WESP) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for WESP) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $130,956 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $63,941 | Jacobs |
| b. Sewer | | $1,091 | Jacobs |
| M. Caustic costs | | $2,728 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for WESP) | | $0 | Jacobs |
| O. Administration (assumed none add'l for WESP) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for WESP) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $120,883 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$319,600** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$1,607,880** | *Calculation* |
| Baseline emissions | tons/year | 4.3 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 3.2 | BART analysis |
| Emissions w/FGC + WESP | tons/year | 0.32 | *Calculation* |
| Reduction due to WESP | Percent | 90.0 | control to 90% |
| Total Emissions Reduction | tons/year | 4.0 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 403,196** | *Calculation* |

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BP BART

Fuel Gas Conditioning & Wet Electrostatic Precipitator Cost Effectiveness Calculation - Naphtha HDS Stripper Reboiler Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $443,322 | Jacobs |
| b. Vessel Installed Cost | $2,330,397 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $723,020 | Jacobs |
| d. Duct Installed Cost | $389,660 | Jacobs |
| e. WESP Installed Cost | $685,732 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $4,572,131 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | $0 | Jacobs |
| h. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $4,572,131 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $1,828,852 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $6,400,983 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | $2,500,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | $8,900,983 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | $1,462,001 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$978,192** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| I. Labor for operations (assumed none add'l for WESP) | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for WESP) | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | $96,015 | Jacobs based on OAQPS |
| L. Utility costs | | |
| a. Electricity (fan & pump) | $36,547 | Jacobs |
| b. Sewer | $667 | Jacobs |
| M. Caustic costs | $1,668 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| N. Overhead (assumed none add'l for WESP) | $0 | Jacobs |
| O. Administration (assumed none add'l for WESP) | $0 | Jacobs |
| P. Insurance (assumed none add'l for WESP) | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | $73,100 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$207,996** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$1,186,189** | *Calculation* |

| | | | |
|---|---|---|---|
| Baseline emissions | tons/year | 2.6 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 2.0 | BART analysis |
| Emissions w/FGC + WESP | tons/year | 0.20 | *Calculation* |
| Reduction due to WESP | Percent | 90.0 | control to 90% |
| Total Emissions Reduction | tons/year | 2.4 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 491,886** | *Calculation* |

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BP BART

Fuel Gas Conditioning & Wet Electrostatic Precipitator Cost Effectiveness Calculation - #1 Reformer Heaters

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $1,845,680 | Jacobs |
| b. Vessel Installed Cost | $8,147,111 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $3,039,067 | Jacobs |
| d. Duct Installed Cost | $1,241,990 | Jacobs |
| e. WESP Installed Cost | $7,507,071 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $21,780,919 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | $0 | Jacobs |
| h. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | 1.3 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $28,315,194 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $11,326,078 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $39,641,272 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $2,500,000 | Jacobs |
| J. Production Loss (due to extended turnaround) | $9,600,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | $51,741,272 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | $16,180,082 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$6,411,295** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| I. Labor for operations (assumed none add'l for WESP) | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for WESP) | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | $632,119 | Jacobs based on OAQPS |
| L. Utility costs | | |
| a. Electricity (fan & pump) | $386,912 | Jacobs |
| b. Sewer | $7,303 | Jacobs |
| M. Caustic costs | $18,258 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| N. Overhead (assumed none add'l for WESP) | $0 | Jacobs |
| O. Administration (assumed none add'l for WESP) | $0 | Jacobs |
| P. Insurance (assumed none add'l for WESP) | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | $809,004 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$1,853,597** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$8,264,892** | *Calculation* |

| | | | |
|---|---|---|---|
| Baseline emissions | tons/year | 28.9 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 21.6 | BART analysis |
| Emissions w/FGC + WESP | tons/year | 2.16 | *Calculation* |
| Reduction due to WESP | Percent | 90.0 | control to 90% |
| Total Emissions Reduction | tons/year | 26.7 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 309,681** | *Calculation* |

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BP BART

Fuel Gas Conditioning & Wet Electrostatic Precipitator Cost Effectiveness Calculation - Coker Charge Heater (#1 North)

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $824,778 | Jacobs |
| b. Vessel Installed Cost | $4,062,352 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $1,379,532 | Jacobs |
| d. Duct Installed Cost | $603,044 | Jacobs |
| e. WESP Installed Cost | $2,012,750 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $8,882,455 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | $0 | Jacobs |
| h. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $8,882,455 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $3,552,982 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $12,435,438 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | $12,435,438 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | $3,257,000 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$1,481,255** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| I. Labor for operations (assumed none add'l for WESP) | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for WESP) | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | $186,532 | Jacobs based on OAQPS |
| L. Utility costs | | |
| a. Electricity (fan & pump) | $98,239 | Jacobs |
| b. Sewer | $1,958 | Jacobs |
| M. Caustic costs | $4,895 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| N. Overhead (assumed none add'l for WESP) | $0 | Jacobs |
| O. Administration (assumed none add'l for WESP) | $0 | Jacobs |
| P. Insurance (assumed none add'l for WESP) | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | $162,850 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$454,474** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$1,935,729** | *Calculation* |

| | | | |
|---|---|---|---|
| Baseline emissions | tons/year | 5.8 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 4.4 | BART analysis |
| Emissions w/FGC + WESP | tons/year | 0.44 | *Calculation* |
| Reduction due to WESP | Percent | 90.0 | control to 90% |
| Total Emissions Reduction | tons/year | 5.4 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 360,317** | *Calculation* |

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BP BART

Fuel Gas Conditioning & Wet Electrostatic Precipitator Cost Effectiveness Calculation - Coker Charge Heater (#2 South)

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $824,778 | Jacobs |
| b. Vessel Installed Cost | | $4,062,352 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $1,379,532 | Jacobs |
| d. Duct Installed Cost | | $603,044 | Jacobs |
| e. WESP Installed Cost | | $2,012,750 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $8,882,455 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| h. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $8,882,455 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | | $3,552,982 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $12,435,438 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $12,435,438 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $3,314,020 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$1,486,637** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for WESP) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for WESP) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $186,532 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $98,239 | Jacobs |
| b. Sewer | | $1,958 | Jacobs |
| M. Caustic costs | | $4,895 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for WESP) | | $0 | Jacobs |
| O. Administration (assumed none add'l for WESP) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for WESP) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $165,701 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$457,325** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$1,943,962** | *Calculation* |
| Baseline emissions | tons/year | 5.9 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 4.4 | BART analysis |
| Emissions w/FGC + WESP | tons/year | 0.44 | *Calculation* |
| Reduction due to WESP | Percent | 90.0 | control to 90% |
| Total Emissions Reduction | tons/year | 5.5 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 355,624** | *Calculation* |

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BP BART

Fuel Gas Conditioning & Wet Electrostatic Precipitator Cost Effectiveness Calculation - Diesel HDS Charge Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $362,840 | Jacobs |
| b. Vessel Installed Cost | $1,995,641 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $602,747 | Jacobs |
| d. Duct Installed Cost | $311,241 | Jacobs |
| e. WESP Installed Cost | $506,362 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $3,778,831 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | $0 | Jacobs |
| h. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $3,778,831 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $1,511,532 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $5,290,363 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | $3,600,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | $8,890,363 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | $768,634 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$911,741** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| I. Labor for operations (assumed none add'l for WESP) | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for WESP) | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | $79,355 | Jacobs based on OAQPS |
| L. Utility costs | | |
| a. Electricity (fan & pump) | $25,307 | Jacobs |
| b. Sewer | $493 | Jacobs |
| M. Caustic costs | $1,232 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| N. Overhead (assumed none add'l for WESP) | $0 | Jacobs |
| O. Administration (assumed none add'l for WESP) | $0 | Jacobs |
| P. Insurance (assumed none add'l for WESP) | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | $38,432 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$144,819** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$1,056,560** | *Calculation* |

| | | | |
|---|---|---|---|
| Baseline emissions | tons/year | 1.4 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 1.0 | BART analysis |
| Emissions w/FGC + WESP | tons/year | 0.10 | *Calculation* |
| Reduction due to WESP | Percent | 90.0 | control to 90% |
| Total Emissions Reduction | tons/year | 1.3 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 833,361** | *Calculation* |

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BP BART

Fuel Gas Conditioning & Wet Electrostatic Precipitator Cost Effectiveness Calculation - Diesel HDS Stabilizer Reboiler

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $425,058 | Jacobs |
| b. Vessel Installed Cost | | $2,242,260 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $691,083 | Jacobs |
| d. Duct Installed Cost | | $379,739 | Jacobs |
| e. WESP Installed Cost | | $635,995 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $4,374,135 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| h. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $4,374,135 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | | $1,749,654 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $6,123,789 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $3,600,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $9,723,789 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $1,274,974 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$1,038,205** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for WESP) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for WESP) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $91,857 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $34,268 | Jacobs |
| b. Sewer | | $619 | Jacobs |
| M. Caustic costs | | $1,547 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for WESP) | | $0 | Jacobs |
| O. Administration (assumed none add'l for WESP) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for WESP) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $63,749 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$192,039** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$1,230,245** | *Calculation* |
| Baseline emissions | tons/year | 2.3 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 1.7 | BART analysis |
| Emissions w/FGC + WESP | tons/year | 0.17 | *Calculation* |
| Reduction due to WESP | Percent | 90.0 | control to 90% |
| Total Emissions Reduction | tons/year | 2.1 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 584,990** | *Calculation* |

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BP BART

Fuel Gas Conditioning & Wet Electrostatic Precipitator Cost Effectiveness Calculation - Reforming Furnace #1 - (North H2 Plant)

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $1,196,137 | Jacobs |
| b. Vessel Installed Cost | | $5,225,874 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $1,841,479 | Jacobs |
| d. Duct Installed Cost | | $800,275 | Jacobs |
| e. WESP Installed Cost | | $3,257,227 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $12,320,991 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| h. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1.3 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $16,017,288 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | | $6,406,915 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $22,424,203 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $23,750,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $46,174,203 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $7,018,059 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$5,020,973** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for WESP) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for WESP) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $336,363 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $165,153 | Jacobs |
| b. Sewer | | $3,169 | Jacobs |
| M. Caustic costs | | $7,922 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for WESP) | | $0 | Jacobs |
| O. Administration (assumed none add'l for WESP) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for WESP) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $350,903 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$863,509** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$5,884,483** | *Calculation* |
| Baseline emissions | tons/year | 12.5 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 9.4 | BART analysis |
| Emissions w/FGC + WESP | tons/year | 0.94 | *Calculation* |
| Reduction due to WESP | Percent | 90.0 | control to 90% |
| Total Emissions Reduction | tons/year | 11.6 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 508,335** | *Calculation* |

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BP BART

Fuel Gas Conditioning & Wet Electrostatic Precipitator Cost Effectiveness Calculation - Reforming Furnace #2 - (South H2 Plant)

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $1,182,092 | Jacobs |
| b. Vessel Installed Cost | | $5,172,056 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $1,819,856 | Jacobs |
| d. Duct Installed Cost | | $792,437 | Jacobs |
| e. WESP Installed Cost | | $3,193,733 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $12,160,174 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| h. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1.3 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $15,808,226 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | | $6,323,290 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $22,131,516 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $23,750,000 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $45,881,516 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $6,883,491 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$4,980,643** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for WESP) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for WESP) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $331,973 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $161,933 | Jacobs |
| b. Sewer | | $3,107 | Jacobs |
| M. Caustic costs | | $7,768 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for WESP) | | $0 | Jacobs |
| O. Administration (assumed none add'l for WESP) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for WESP) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $344,175 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$848,955** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$5,829,598** | *Calculation* |
| Baseline emissions | tons/year | 12.3 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 9.2 | BART analysis |
| Emissions w/FGC + WESP | tons/year | 0.92 | *Calculation* |
| Reduction due to WESP | Percent | 90.0 | control to 90% |
| Total Emissions Reduction | tons/year | 11.4 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 513,438** | *Calculation* |

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BP BART

Fuel Gas Conditioning & Wet Electrostatic Precipitator Cost Effectiveness Calculation - R-1 HC Reactor Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $536,599 | Jacobs |
| b. Vessel Installed Cost | $2,747,364 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $876,428 | Jacobs |
| d. Duct Installed Cost | $454,861 | Jacobs |
| e. WESP Installed Cost | $944,998 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $5,560,250 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | $0 | Jacobs |
| h. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $5,560,250 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $2,224,100 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $7,784,350 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | $7,784,350 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | $2,034,484 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$926,829** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| I. Labor for operations (assumed none add'l for WESP) | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for WESP) | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | $116,765 | Jacobs based on OAQPS |
| L. Utility costs | | |
| a. Electricity (fan & pump) | $50,106 | Jacobs |
| b. Sewer | $919 | Jacobs |
| M. Caustic costs | $2,298 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| N. Overhead (assumed none add'l for WESP) | $0 | Jacobs |
| O. Administration (assumed none add'l for WESP) | $0 | Jacobs |
| P. Insurance (assumed none add'l for WESP) | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | $101,724 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$271,813** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$1,198,642** | *Calculation* |

| | | | |
|---|---|---|---|
| Baseline emissions | tons/year | 3.6 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 2.7 | BART analysis |
| Emissions w/FGC + WESP | tons/year | 0.27 | *Calculation* |
| Reduction due to WESP | Percent | 90.0 | control to 90% |
| Total Emissions Reduction | tons/year | 3.4 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 357,185** | *Calculation* |

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BP BART

Fuel Gas Conditioning & Wet Electrostatic Precipitator Cost Effectiveness Calculation - R-4 HC Reactor Heater

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $350,668 | Jacobs |
| b. Vessel Installed Cost | | $1,867,180 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $557,385 | Jacobs |
| d. Duct Installed Cost | | $344,792 | Jacobs |
| e. WESP Installed Cost | | $444,456 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $3,564,480 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| h. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $3,564,480 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | | $1,425,792 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $4,990,271 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $4,990,271 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $957,485 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$561,426** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for WESP) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for WESP) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $74,854 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $25,942 | Jacobs |
| b. Sewer | | $432 | Jacobs |
| M. Caustic costs | | $1,081 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for WESP) | | $0 | Jacobs |
| O. Administration (assumed none add'l for WESP) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for WESP) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $47,874 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$150,184** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$711,610** | *Calculation* |
| Baseline emissions | tons/year | 1.7 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 1.3 | BART analysis |
| Emissions w/FGC + WESP | tons/year | 0.13 | *Calculation* |
| Reduction due to WESP | Percent | 90.0 | control to 90% |
| Total Emissions Reduction | tons/year | 1.6 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 450,576** | *Calculation* |

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BP BART

Fuel Gas Conditioning & Wet Electrostatic Precipitator Cost Effectiveness Calculation - 1st Stage HC Fractionator Reboiler

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | | |
|---|---|---|---|
| **DIRECT COSTS** | | **COST** | **Source** |
| A. Purchased Equipment | | | |
| a. Blower & Blower Motor Installed Cost | | $833,240 | Jacobs |
| b. Vessel Installed Cost | | $4,215,488 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | | $1,439,591 | Jacobs |
| d. Duct Installed Cost | | $539,359 | Jacobs |
| e. WESP Installed Cost | | $2,160,902 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | | $9,188,581 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | | $0 | Jacobs |
| h. Freight (included in Project Contingency) | | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | | $9,188,581 | *Calculation* |
| **INDIRECT COSTS** | | | |
| C. Indirect Installation | | | |
| a. Engineering and Supervision (included in Project Contingency) | | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | | $0 | Jacobs |
| d. Startup (included in Project Contingency) | | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | | $3,675,432 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | | $12,864,013 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | | $12,864,013 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | | $3,945,121 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | | **$1,586,663** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | | |
| **DIRECT OPERATING COSTS (DOC)** | | | |
| I. Labor for operations (assumed none add'l for WESP) | | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for WESP) | | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | | $192,960 | Jacobs based on OAQPS |
| L. Utility costs | | | |
| a. Electricity (fan & pump) | | $94,508 | Jacobs |
| b. Sewer | | $2,102 | Jacobs |
| M. Caustic costs | | $5,256 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | | |
| N. Overhead (assumed none add'l for WESP) | | $0 | Jacobs |
| O. Administration (assumed none add'l for WESP) | | $0 | Jacobs |
| P. Insurance (assumed none add'l for WESP) | | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | | $197,256 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | | **$492,082** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | | **$2,078,745** | *Calculation* |
| Baseline emissions | tons/year | 7.0 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 5.3 | BART analysis |
| Emissions w/FGC + WESP | tons/year | 0.53 | *Calculation* |
| Reduction due to WESP | Percent | 90.0 | control to 90% |
| Total Emissions Reduction | tons/year | 6.5 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 319,447** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quality Planning and Standards (OAQPS).

BP BART

Fuel Gas Conditioning & Wet Electrostatic Precipitator Cost Effectiveness Calculation - 2nd Stage HC Fractionator Reboiler

Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $779,087 | Jacobs |
| b. Vessel Installed Cost | $3,988,363 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $1,350,608 | Jacobs |
| d. Duct Installed Cost | $502,948 | Jacobs |
| e. WESP Installed Cost | $1,942,907 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $8,563,913 | *Calculation* |
| f. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| g. Sales tax (included in Project Contingency) | $0 | Jacobs |
| h. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| Retrofit Factor (ease of retrofit) | 1 | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $8,563,913 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $3,425,565 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $11,989,478 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| J. Production Loss (due to extended turnaround) | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | $11,989,478 | *Calculation* |
| Fuel Gas Conditioning Total Capital Investment | $3,296,002 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$1,442,841** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| I. Labor for operations (assumed none add'l for WESP) | $0 | Jacobs |
| J. Supervisory Labor (assumed none add'l for WESP) | $0 | Jacobs |
| K. Maintenance Labor and Costs (0.015*TCI) | $179,842 | Jacobs based on OAQPS |
| L. Utility costs | | |
| a. Electricity (fan & pump) | $84,026 | Jacobs |
| b. Sewer | $1,890 | Jacobs |
| M. Caustic costs | $4,725 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| N. Overhead (assumed none add'l for WESP) | $0 | Jacobs |
| O. Administration (assumed none add'l for WESP) | $0 | Jacobs |
| P. Insurance (assumed none add'l for WESP) | $0 | Jacobs |
| Fuel Gas Conditioning Operating Costs | $164,800 | BP Engineering Estimate / Jacobs |
| ***Control Combination - Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$435,284** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)*** | **$1,878,125** | *Calculation* |

| | | | |
|---|---|---|---|
| Baseline emissions | tons/year | 5.9 | BP Estimation for BART |
| Emissions w/FGC only | tons/year | 4.4 | BART analysis |
| Emissions w/FGC + WESP | tons/year | 0.44 | *Calculation* |
| Reduction due to WESP | Percent | 90.0 | control to 90% |
| Total Emissions Reduction | tons/year | 5.4 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 345,458** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quaility Planning and Standards (OAQPS).

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Attachment: Compact Disk Containing CALPUFF Modeling Files

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# BART DETERMINATION MODELING ANALYSIS

BP Cherry Point Refinery
Blaine, Washington

## 1.0 INTRODUCTION

The Washington State Department of Ecology (Ecology) requires the BP Cherry Point Refinery (BP) to submit a Best Available Retrofit Technology (BART) technical analysis. Under Ecology and U.S. Environmental Protection Agency (EPA) rules and guidance, sources subject to BART must conduct modeling analyses to assess the relative merits of different control strategies to improve visibility in Class I areas.[1] Geomatrix prepared this report to describe two regional air quality model simulations we conducted to support a BART determination analysis for BP.

The BART analysis evaluates potential technologies for control of oxides of nitrogen (NOx), sulfur dioxide ($SO_2$), and $PM_{10}$ (particles less than 10 microns in diameter) emissions from BART-eligible units at BP. As part of the evaluation, Geomatrix applied the CALPUFF modeling system to assess visibility impacts per the recommendations included in the *BART Guidelines*.[1] We followed a *BART Modeling Protocol* developed by the Idaho Department of Environmental Quality (IDEQ), Oregon Department of Environmental Quality (ODEQ), and Ecology for BART exemption and BART determination analyses.[2] The *BART Modeling Protocol* is designed to be conservative and will likely overstate both the impacts of BP NOx, $SO_2$, and $PM_{10}$ emissions on regional haze and the likely benefits of emission controls to improve visibility in Class I areas.

The remainder of this report describes a BART determination modeling analysis for NOx, $SO_2$, and $PM_{10}$ emissions from BP BART-eligible units. The report will describe the modeling domain and identify any changes to the protocol used in our study. The report includes a discussion of the baseline emission rates used in simulations for the BP units, emission reductions attributable to BART controls, and how emission units were characterized in the simulations. The report concludes with a presentation of the dispersion model results.

---

[1] 40 CFR Part 51. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations; Final Rule. pg 39129. July 6, 2005. Appendix Y, "Guideline for Best Available Retrofit Technology Determination" (*BART Guidelines*) details EPA's requirements and guidance for states for conducting BART analyses.

[2] *Modeling Protocol for Washington, Oregon, and Idaho: Protocol for the Application of the CALPUFF Modeling System Pursuant to the Best Available Retrofit Technology (BART) Regulation*. Final Version October 11, 2006.

## 2.0 BART-ELIGIBLE SOURCES

Ecology compiled a list of potential BART-eligible units at BP based on an initial review of historical operations at the Cherry Point Refinery. This initial list was modified with units being added and dropped after discussions with Ecology. BART-eligible units that have been reconstructed, removed, or replaced since August 7, 1977 can be eliminated from the analysis. However, those BART-eligible sources that have been modified (even with Best Available Control Technology [BACT]) – but not reconstructed – need to be included in the analysis.[3] For instance, the Boiler No. 2 has been removed and therefore does not have to be considered in the analysis. The South Vacuum Heater, on the other hand, was modified and had BACT installed, but was not reconstructed, removed, and/or replaced; therefore, it must remain in the analysis.

Nineteen emission units from the BART-eligible unit list developed for BP are considered in this modeling analysis:[4]

- Crude Heater
- South Vacuum Heater
- No. 1 Reformer Heaters
- Naphtha HDS Charge Heater
- Naphtha HDS Stripper Reboiler
- 1st Stage Hydrocracker Fractionator Reboiler
- 2nd State Hydrocracker Fractionator Reboiler
- R-1 Hydrocracker Reactor Heater
- R-4 Hydrocracker Reactor Heater
- North Coker Charge Heater (No. 1)
- South Coker Charge Heater (No. 2)
- Diesel HDS Charge Heater
- Diesel HDS Stabilizer Reboiler
- No. 1 H2 Reforming Furnace
- No. 2 H2 Reforming Furnace
- Low Pressure Flare

[3] 40 CFR Part 51 Appendix Y.II.A.2. "How are modifications treated under the BART provision?"

[4] Letter from Valerie Lagen, BP, to Alan Newman, Ecology, dated January 31, 2007; and Letter from Alan Newman, Ecology, to Valerie Lagen, BP, dated February 7, 2007.

- High Pressure Flare
- SRU & TGU (Sulfur Incinerator)
- South Dock

Several potential BART-eligible sources from the original Ecology list were excluded from the BART determination modeling analysis for the following reasons:

- #1 and #2 Calciners: Notice of Construction approved after BART-applicable time frame
- #2 Reformer Heater: Constructed after BART-applicable time frame
- Floating Roof Storage Tanks: Negligible NOx, $SO_2$, and $PM_{10}$ emissions
- Fixed Roof Storage Tanks: Negligible NOx, $SO_2$, and $PM_{10}$ emissions
- Flare Gas Recovery: Not an emission unit
- API Separators: Negligible NOx, $SO_2$, and $PM_{10}$ emissions
- LPG Loading Racks: Negligible NOx, $SO_2$, and $PM_{10}$ emissions
- #1 Cooling Tower: No NOx or $SO_2$ emissions. Particulate emissions in the cooling tower are negligible
- Green Coke Loadout: The Green Coke Loadout was functionally replaced by the #1 and #2 Calciners and would only be used during upset conditions. There was no green coke loaded during the Baseline (2003-2005) period
- Boiler No. 1 and Boiler No. 3: As part of the Boiler Replacement Project,[5] BP has committed to decommissioning Boiler No. 1 and Boiler No. 3 by the end of 2010. As such, these units are no longer BART-eligible and are not included in this analysis

The next section describes the derivation of emission rates and stack parameters for BP BART-eligible units included in the modeling analysis.

[5] Boiler Replacement Project NOC/PSD Permit Application submitted May 4, 2007.

## 3.0 BART DETERMINATION ANALYSIS EMISSION RATES

The BART determination analysis compares the benefits of additional NOx, $SO_2$, and $PM_{10}$ controls towards reducing regional haze in Class I areas against the results from a simulation of baseline conditions. Simulations of emissions from the BP BART-eligible units were performed for the following two cases:

- Baseline – Maximum 24-hour NOx, $SO_2$, and $PM_{10}$ emissions during 2003-2005
- BART – Same as the Baseline except NOx controls on the Diesel HDS Charge Heater , Diesel HDS Stabilizer Reboiler, 1st Stage Hydrocracker Fractionator Reboiler, and the R-1 Hydrocracker Reactor Heater

The *BART Modeling Protocol* requires that the highest daily NOx, $PM_{10}$, and $SO_2$ emission rates during 2003-2005 be used for the Baseline case. The period for the baseline emissions matches the timeframe of the meteorological dataset (2003-2005) described in the *BART Modeling Protocol*. The methods used to estimate emission rates for the Baseline and BART cases are described in the remainder of this section.

### 3.1 BASELINE EMISSION RATES

Table 3-1 shows the maximum calendar day NOx, $SO_2$, and $PM_{10}$ emission rates for each eligible unit used in the Baseline simulations. Emission rates for each unit and pollutant were calculated independently from daily emission estimates during 2003-2005. The daily summaries were ranked and the highest emission rate for each pollutant and unit were selected for the simulations. Section 2.5 of the main body of this report also discussed how Baseline emissions were derived.

### 3.2 BART EMISSION RATES

Table 3-2 presents the $SO_2$, $PM_{10}$, and NOx emission rates used for simulations of the BART case. This table reflects the proposed NOx, $SO_2$, and $PM_{10}$/$PM_{2.5}$ BART emissions that are summarized in Tables 3-7, 3-10, and 3-13 of the main body of this report. Compared with the modeling baseline, NOx emissions are reduced by the recent installation of LNB installed on the Diesel HDS Charge Heater (2006), Diesel HDS Stabilizer Reboiler (2006), and the R-1 Hydrocracker Reactor heater (2006), and by the proposed installation of LNB on the 1st Stage Hydrocracker Fractionator Reboiler. Low NOx burners recently retrofitted to the South Vacuum

heater (February 2005) and 2nd Stage HC Fractionator Reboiler (November 2003) are also BART for those units, but the emission reductions were also included in the Baseline modeling emissions.

### 3.3 BASELINE AND BART STACK PARAMETERS

Stack parameters for BART emission units were reviewed and updated for use in the BART modeling analysis. The BART modeling analysis is expected to use the average stack parameters during normal operation. Most of the stack heights were measured during a walkthrough by BP personnel. Those that could not be measured were reviewed against facility drawings. The stack diameters were obtained from facility drawings.

The stack temperatures are based on a three-year average (2003 to 2005), excluding turnarounds. The stack flow rates were calculated using an F factor (8710 dscf/MMBtu for natural gas), and three-year average stack temperature, refinery fuel gas heat content, and excess oxygen. The stack coordinates were taken from previous modeling and facility plot plans.

The source locations and stack parameters for each modeled emission unit are identified in Tables 3-3 and 3-4, respectively.

## 4.0 CALPUFF MODELING PROCEDURES

Geomatrix applied the CALPUFF modeling system to assess Class I area regional haze caused by the $SO_2$, NOx, and $PM_{10}$ emissions in the Baseline and BART cases described in the previous section. Features of the CALPUFF modeling system include the ability to consider: secondary aerosol formation; gaseous and particle deposition; wet and dry deposition processes; complex three-dimensional wind regimes; and the effects of humidity on regional visibility.

Geomatrix used Version 6.112 of the CALPUFF modeling system for the simulations per the recommendations of the *BART Modeling Protocol* for Washington, Oregon, and Idaho.[6] The simulations were performed using a 2003-2005 meteorological database prepared by Geomatrix for BART related analyses in the three states. With the exception of the ozone data discussed in Section 4.2, the CALPUFF modeling procedures follow the *BART Modeling Protocol*.

### 4.1 CALPUFF DOMAIN AND RECEPTORS

Figure 4-1 displays the CALPUFF modeling domain within the larger CALMET domain used for BART simulations in Washington, Oregon and Idaho. The CALPUFF computation domain was selected using a circle with a 300-kilometer (km) radius surrounding BP. All Class I areas located inside of the circle are included in the BART determination modeling. The CALPUFF computation domain includes a buffer of approximately 50 km from any Class I area touched by the 300-km circle.

Figure 4-2 shows the CALPUFF domain and the Class I areas considered in the analysis. The eight Class I areas included in the visibility impact analysis include: Alpine Lakes Wilderness, Glacier Peak Wilderness, Goat Rocks Wilderness, Mt. Adams Wilderness, Mt. Rainier National Park, North Cascades National Park, Olympic National Park, and Pasayten Wilderness

Receptor locations and elevations for the Class I areas were obtained from a database available from the NPS.[7] In addition to the Class I area receptors, CALPUFF predictions were also obtained at each grid point within the 4-km mesh size computational domain. These receptors were used only for diagnostic purposes and to prepare some of the figures in this report.

---

[6] Although a later version of the modeling system is now available, Ecology requests Version 6.112 be applied for consistency with previously submitted BART exemption analyses from other sources. This version of the CALPUFF modeling system is also compatible with a large meteorological database prepared on Ecology's behalf by Geomatrix for BART simulations.

[7] Receptor locations, elevations, and boundaries for each Class I area can be obtained from the NPS at: http://www2.nature.nps.gov/air/maps/Receptors/index.cfm.

## 4.2 OZONE DATA

The *BART Modeling Protocol* recommends a constant ozone background concentration of 60 ppb for BART simulations. However, it has become common practice for both BART analyses and New Source Review assessments of Class I areas to use actual ozone observations within Washington, Oregon, and Idaho to characterize background ozone concentrations. ODEQ prepared such a database for BART sources to use in their assessments.

The ODEQ database does not contain Canadian monitoring data and the BP domain extends into British Columbia. Geomatrix supplemented the ODEQ ozone database for 2003-2005 by adding data from seven monitoring stations in southern British Columbia. The ozone station locations near the study domain are shown in Figure 4-3. The database was submitted by Geomatrix and subsequently approved by Ecology for BART and New Source Review analyses.[8]

## 4.3 CALPUFF EMISSION DATA

Section 3 of this report presented the highest daily NOx, $PM_{10}$, and $SO_2$ emission rates used for the simulations for the Baseline and BART determination cases. Prior to the CALPUFF simulations, $PM_{10}$ emissions must be divided into coarse particles (PMC) and $PM_{2.5}$ (particles less than 2.5 microns in diameter). $PM_{2.5}$ is further divided into one to five species, including: soot or elemental carbon (EC), fine soil particles (PMF), organic carbon (OC),[9] sulfate ($SO_4$), and nitrate ($NO_3$). These species have different scattering efficiencies when combined with relative humidity adjustment factors and predicted aerosol concentrations are used to calculate visual extinction.

Geomatrix speciated Baseline and BART case $PM_{10}$ emissions according to the fractions listed in Table 3-1. The $PM_{2.5}/PM_{10}$ ratios and $PM_{2.5}$ fractions were taken from a database provided by Ecology for use in BART modeling analyses. We understand the $PM_{2.5}$ fractions in the database are based on profiles recommended by the EPA for the Community Multi-Scale Air Quality (CMAQ) model.[10,11] CMAQ is the preferred regulatory model for $PM_{2.5}$ and regional haze

---

[8] Email from Clint Bowman, Ecology to Ken Richmond, Geomatrix, Subj: *Addition of BC Ozone Observations to Ozone.dat.* December 20, 2007.

[9] For the purposes of post-processing by CALPOST, the species OC is labeled SOA (secondary organic aerosol) in the CALPUFF input and output files. CALPOST actually looks for "SOA" when calculating extinction. We assume all OC emitted forms SOA.

[10] EPA website containing PM speciation by source categories: http://www.epa.gov/ttn/chief/emch/speciation.

[11] NPS has developed $PM_{10}$ speciation profiles for several of the major source categories and these are commonly used to divide $PM_{10}$ emissions into species for BART analyses. However, the NPS profiles do not include process

simulations. The CMAQ profile database is indexed by Source Classification Code (SCC). The SCC assigned to each BART unit at BP is also listed in Table 4-1.

A summary of the CALPUFF simulation emission rates for the Baseline and BART cases are shown in Table 4-2 and Table 4-3, respectively. The Ecology profile database divides $PM_{10}$ emissions into PMC, PMF, EC, OC, ammonium nitrate, and ammonium sulfate. $SO_4$ and $NO_3$ emissions in the CALPUFF input files were calculated based on the respective ammonium sulfate and ammonium nitrate in the NPS profile after accounting for the change in molecular weight.

Geomatrix combined some of the emissions from similar individual stacks to expedite the simulations as shown in Table 4-2 and Table 4-3. In some instances we combined a single BART-eligible unit's emissions when they are emitted from two adjacent similar stacks. Other examples include the #1 and #2 Coke Charge Heaters that are located close to one another and have similar release characteristics. Emissions from these stacks were combined and simulated as a single stack using the average stack parameters and locations. In one case, emissions from three relatively small units were combined in a single stack. Units with relatively large emissions and/or dissimilar stack parameters were simulated individually.

Geomatrix does not believe combining the emissions from individual stacks significantly affects the results of the modeling analysis as long as the stack parameters are similar. The visibility impacts in some instances might be slightly over-predicted as the simulations neglects the initial separation of the individual plumes. However, the stacks are relatively close to one another and the Class I areas of interest some distance away. Note the same stacks were combined for both the Baseline and BART cases and these combinations should not bias the results of the analysis toward one case or the other.

## 4.4 CALPOST POST-PROCESSING

Geomatrix applied CALPOST to post-process the CALPUFF output files and calculate the change to the Haze Index (HI) predicted by aerosols emitted and formed from the BP units. Background HIs for each Class I area were calculated using CALPOST Method 6 and the monthly average relative humidity adjustment factors and aerosol concentrations listed in Appendix B of the *BART Modeling Protocol*. The background extinction in the protocol

heaters, flares and the other BART units at the BP Cherry Point Refinery. The NPS speciation profiles can be found at http://www2.nature.nps.gov/air/permits/ect/index.cfm.

represents the hypothetical "natural" background on the 20 percent best visibility days of the year.

As recommended by the *BART Guidelines*, Geomatrix used the 98$^{th}$ percentile change to the daily Haze Index (ΔHI), in units of deciviews (dv), as a visibility metric to assess the significance of results from the two emission cases. The 98$^{th}$ percentiles within each Class I area were estimated from the 8$^{th}$ highest ΔHI of each year and the 22$^{nd}$ highest in three years. The time-series lists in the CALPOST output files that identify the maximum daily ΔHI within each Class I area were sorted to obtain the required 98$^{th}$ percentiles.

Geomatrix also summarized the simulations by comparing the number of days where the predicted ΔH exceeds 0.5 dv within each Class I area. This is the screening criterion for BART exemption. According to *BART Guidelines*, a ΔHI of less than 0.5 dv when compared to natural conditions does not cause or contribute to impairment of visibility.

## 5.0 BASELINE AND BART DETERMINATION MODELING RESULTS

Table 5-1 displays the number of days in three years predicted by the CALPUFF modeling system where the ΔHI significance criterion of 0.5 dv was exceeded for each Class I area and emission case. For the Baseline case, the number of days in three years exceeding the screening criterion range from 57 days in Olympic National Park to no days in the Glacier Peak, Mt. Adams and Pasayten Wilderness areas. For the BART case, the number of days exceeding the criterion is reduced by about 7 percent for Olympic National Park. Overall the total number of days exceeding the 0.5 dv criterion is reduced from 73 to 63 days or by about 14 percent due to the BART controls.

Table 5-2 presents the three-year 98$^{th}$ percentile ΔHI predicted for each Class I area and emission case. This metric is related to both the frequency and magnitude of the predicted change to the haze index. The highest potential impacts to regional haze are predicted in Olympic National Park followed by the North Cascades National Park, Alpine Lakes Wilderness and Glacier Peak Wilderness. In the BART simulations, the mean 98$^{th}$ percentile ΔHI for areas of interest is about 94 percent of the prediction for Baseline emissions. For Olympic National Park, the 98$^{th}$ percentile ΔHI predicted by the BART simulation is 93 percent of the prediction with Baseline emissions.

Based on the BART exemption criterion, the Olympic National Park is the only Class I area where BP's BART-eligible unit emissions have the potential to impair visibility when compared to natural conditions. The CALPUFF simulations of the Baseline case did not exceed this conservative screening level in any other area of interest.

The yearly 98$^{th}$ percentile ΔHIs for each of the three years are shown in Table 5-3. For the Baseline simulations, the higher impacts are generally predicted in 2003 for three of the Class I areas, in 2004 for four of the Class I areas, and in 2005 for Olympic National Park This same trend is followed in the BART case simulations. The year-to-year variability is the lowest for the Olympic National Park and the highest for Mt. Rainier National Park.

The highest predicted extinctions are predicted in the Olympic and North Cascades National Parks. Figure 5-1 and Figure 5-2 show time-series of the predicted maximum daily ΔHI in the North Cascades National Park and Olympic National Park, respectively. For both the Baseline and BART cases, the highest potential changes to the HI occur during the summer for North Cascades National Park, while the highest predictions in the Olympic National Park tend to

occur during the winter months. Flow towards the Olympic National Park occurs less often than the prevailing westerly flow aloft, but is associated with cold temperatures during the winter months. The CALPUFF chemistry algorithms favor nitrate formation during such wintertime episodes and the highest changes to extinction are predicted in Olympic National Park under such conditions.

Table 5-4 and Table 5-5 list the average extinction budgets for the top 98$^{th}$ percentile days for the Baseline and BART cases, respectively.[12] Typically in the Baseline simulations, about 73 percent of the extinction budgets on the worst days are caused by nitrate aerosols. The nitrate aerosol contribution is most important in the Olympic National Park. With the reduction in NOx emissions, the BART case results are slightly less influenced by nitrate formation and on average the nitrate aerosols contribute to about 71 percent of the budgets. The non-hygroscopic components (EC, OC, PMC, and PMF) of the $PM_{10}$ emissions do not contribute significantly to the visibility impairment in either the Baseline or BART cases.

Figure 5-3 and Figure 5-4 show the maximum 24-hour extinction coefficients predicted for the Baseline and BART cases, respectively.[13] The highest predictions for both cases are associated with stagnation conditions and are generally confined to lowland areas. The figures depict flow from the north into Puget Sound, sometimes flowing out the Strait of Juan de Fuca, and southerly flow towards the Straits of Georgia and occasionally up the lower Fraser River Valley. The Class I areas in western Washington are in mountainous areas and plumes from BP tend to affect only the lower elevations near their boundaries.

The overall day with the associated highest 98$^{th}$ percentile ΔHI is February 22, 2005 for both the Baseline and BART cases. Figure 5-5 and Figure 5-6 display the ΔHI predictions using the background aerosol and humidity corrections factors for Olympic National Park. This day was characterized by light, but persistent winds from the northeast out of the Lower Fraser River Valley, transporting the BP plumes south, then out the Strait of Juan De Fuca. Temperatures were a few degrees above freezing promoting the formation of nitrate aerosols. Note, the BP plume touches the northern boundary of Olympic National Park and the predicted ΔHI is not representative of the whole Class I area.

[12] The top 98$^{th}$ percentile days are the corresponding 8$^{th}$ highest ΔHI of each year and the 22$^{nd}$ highest in three-years within each Class I area

[13] The figures were prepared from the highest 24-hour predictions excluding background, using the monthly relative humidity correction factors for the Olympic National Park.

Geomatrix prepared the attached compact disk containing the modeling files for both the Baseline and BART cases. In addition to the CALPUFF and CALPOST files, spreadsheets are included that include the extinction budgets for the top 22 days in 2003-2005 and the top 8 days in each of the individual years. The files associated with the meteorological database have all ready been provided to regulatory agencies in the Pacific Northwest, including Ecology.

# TABLES

# TABLE 3-1

## BASELINE EMISSION RATES

| Source Name | WED [2] No. | Activity (MMBtu/hr) | $SO_2$ [1] | | NOx [1] | | $PM_{10}$ [1] | |
|---|---|---|---|---|---|---|---|---|
| | | | EF (lb/MMBtu) | Rate (lb/hr) | EF (lb/MMBtu) | Rate (lb/hr) | EF (lb/MMBtu) | Rate (lb/hr) |
| Coker Charge Heater (#1 North) | 40 | 142.8 | 0.0547 | 7.8 | 0.0620 | 8.9 | 0.0093 | 1.3 |
| Coker Charge Heater (#2 South) | 41 | 145.3 | 0.0547 | 7.9 | 0.0621 | 9.0 | 0.0093 | 1.3 |
| Crude Heater | 10 | 593.2 | 0.0338 | 20.0 | 0.1850 | 109.7 | 0.0093 | 5.5 |
| Diesel HDS Charge Heater | 50 | 33.7 | 0.0364 | 1.2 | 0.0980 | 3.3 | 0.0093 | 0.3 |
| Diesel HDS Stab Reboiler | 51 | 55.9 | 0.0364 | 2.0 | 0.0980 | 5.5 | 0.0093 | 0.5 |
| South Dock Combustor | 45 | - | - | 0.0 | - | 6.6 | - | 0.0 |
| Reforming Furnace #1 (North H2 Plant, Stack 1) | 60 | 153.9 | 0.0364 | 5.6 | 0.0980 | 15.1 | 0.0093 | 1.4 |
| Reforming Furnace #1 (North H2 Plant, Stack 2) | 60 | 153.9 | 0.0364 | 5.6 | 0.0980 | 15.1 | 0.0093 | 1.4 |
| Reforming Furnace #2 (South H2 Plant, Stack 1) | 61 | 150.9 | 0.0364 | 5.5 | 0.0980 | 14.8 | 0.0093 | 1.4 |
| Reforming Furnace #2 (South H2 Plant, Stack 2) | 61 | 150.9 | 0.0364 | 5.5 | 0.0980 | 14.8 | 0.0093 | 1.4 |
| Naphtha HDS Stripper Reboiler | 23 | 64.1 | 0.0364 | 2.3 | 0.0979 | 6.3 | 0.0093 | 0.6 |
| High Pressure Flare | 110 | - | - | 2.7 | 0.5251 | 2.6 | - | 0.3 |
| 1st Stage HCR Frac Reboiler | 30 | 173.0 | 0.0364 | 6.3 | 0.1499 | 25.9 | 0.0093 | 1.6 |
| 2nd Stage HCR Frac Reboiler | 31 | 144.5 | 0.0364 | 5.3 | 0.0570 | 8.2 | 0.0093 | 1.3 |
| R-1 HCR Reactor Heater | 32 | 89.2 | 0.0364 | 3.3 | 0.0980 | 8.7 | 0.0093 | 0.8 |
| R-4 HCR Reactor Heater | 33 | 42.0 | 0.0364 | 1.5 | 0.0981 | 4.1 | 0.0093 | 0.4 |
| Low Pressure Flare | 111 | - | - | 4.6 | 0.4566 | 3.8 | - | 0.4 |
| Naphtha HDS Charge Heater | 22 | 106.0 | 0.0364 | 3.9 | 0.0980 | 10.4 | 0.0093 | 1.0 |
| #1 Reformer Heaters - 1 & 2 | 20 | 354.7 | 0.0364 | 12.9 | 0.1500 | 53.2 | 0.0093 | 3.3 |
| #1 Reformer Heaters - 3 & 4 | 20 | 354.7 | 0.0364 | 12.9 | 0.1500 | 53.2 | 0.0093 | 3.3 |
| SRU and TGU | 120 | - | - | 8.5 | 0.0685 | 1.4 | - | 0.2 |
| South Vacuum Heater | 12 | 186.4 | 0.0413 | 7.7 | 0.0389 | 7.3 | 0.0093 | 1.7 |
| | | | Total | 133.2 | | 387.9 | | 29.7 |

1. Estimated maximum 24-hour emission rates during 2003-2005
2. Washington Emission Data number or identification

Geomatrix

# TABLE 3-2

## BART EMISSION RATES

| Source Name | WED [2] No. | Activity (MMBtu/hr) | $SO_2$ [1] | | NOx [1] | | $PM_{10}$ [1] | |
|---|---|---|---|---|---|---|---|---|
| | | | EF (lb/MMBtu) | Rate (lb/hr) | EF (lb/MMBtu) | Rate (lb/hr) | EF (lb/MMBtu) | Rate (lb/hr) |
| Coker Charge Heater (#1 North) | 40 | 142.8 | 0.0547 | 7.8 | 0.0620 | 8.9 | 0.0093 | 1.3 |
| Coker Charge Heater (#2 South) | 41 | 145.3 | 0.0547 | 7.9 | 0.0621 | 9.0 | 0.0093 | 1.3 |
| Crude Heater | 10 | 593.2 | 0.0338 | 20.0 | 0.1850 | 109.7 | 0.0093 | 5.5 |
| Diesel HDS Charge Heater | 50 | 33.7 | 0.0364 | 1.2 | 0.0310 | 1.0 | 0.0093 | 0.3 |
| Diesel HDS Stab Reboiler | 51 | 55.9 | 0.0364 | 2.0 | 0.0280 | 1.6 | 0.0093 | 0.5 |
| South Dock Combustor | 45 | - | - | 0.0 | - | 6.6 | - | 0.0 |
| Reforming Furnace #1 (North H2 Plant, Stack 1) | 60 | 153.9 | 0.0364 | 5.6 | 0.0980 | 15.1 | 0.0093 | 1.4 |
| Reforming Furnace #1 (North H2 Plant, Stack 2) | 60 | 153.9 | 0.0364 | 5.6 | 0.0980 | 15.1 | 0.0093 | 1.4 |
| Reforming Furnace #2 (South H2 Plant, Stack 1) | 61 | 150.9 | 0.0364 | 5.5 | 0.0980 | 14.8 | 0.0093 | 1.4 |
| Reforming Furnace #2 (South H2 Plant, Stack 2) | 61 | 150.9 | 0.0364 | 5.5 | 0.0980 | 14.8 | 0.0093 | 1.4 |
| Naphtha HDS Stripper Reboiler | 23 | 64.1 | 0.0364 | 2.3 | 0.0979 | 6.3 | 0.0093 | 0.6 |
| High Pressure Flare | 110 | - | - | 2.7 | 0.5251 | 2.6 | - | 0.3 |
| 1st Stage HCR Frac Reboiler | 30 | 173.0 | 0.0364 | 6.3 | 0.0500 | 8.6 | 0.0093 | 1.6 |
| 2nd Stage HCR Frac Reboiler | 31 | 144.5 | 0.0364 | 5.3 | 0.0570 | 8.2 | 0.0093 | 1.3 |
| R-1 HCR Reactor Heater | 32 | 89.2 | 0.0364 | 3.3 | 0.0200 | 1.8 | 0.0093 | 0.8 |
| R-4 HCR Reactor Heater | 33 | 42.0 | 0.0364 | 1.5 | 0.0981 | 4.1 | 0.0093 | 0.4 |
| Low Pressure Flare | 111 | - | - | 4.6 | 0.4566 | 3.8 | - | 0.4 |
| Naphtha HDS Charge Heater | 22 | 106.0 | 0.0364 | 3.9 | 0.0980 | 10.4 | 0.0093 | 1.0 |
| #1 Reformer Heaters - 1 & 2 | 20 | 354.7 | 0.0364 | 12.9 | 0.1500 | 53.2 | 0.0093 | 3.3 |
| #1 Reformer Heaters - 3 & 4 | 20 | 354.7 | 0.0364 | 12.9 | 0.1500 | 53.2 | 0.0093 | 3.3 |
| SRU and TGU | 120 | - | - | 8.5 | 0.0685 | 1.4 | - | 0.2 |
| South Vacuum Heater | 12 | 186.4 | 0.0413 | 7.7 | 0.0389 | 7.3 | 0.0093 | 1.7 |
| | | | Total | 133.2 | | 357.5 | | 29.7 |

1. Estimated maximum 24-hour emission rates during 2003-2005
2. Washington Emission Data number or identification.

## TABLE 3-3
## BASELINE AND BART SOURCE LOCATIONS

| Source Name | UTM Coordinates (m) [2] | | LCC Coordinates [1] (m) | | Elev (m) [3] |
|---|---|---|---|---|---|
| | East | North | East | West | |
| Coker Charge Heater (#1 North) | 519,309 | 5,414,561 | -122.872 | -10.982 | 31.4 |
| Coker Charge Heater (#2 South) | 519,309 | 5,414,549 | -122.872 | -10.994 | 31.4 |
| Crude Heater | 519,630 | 5,414,540 | -122.563 | -11.010 | 33.8 |
| Diesel HDS Charge Heater | 519,575 | 5,414,631 | -122.614 | -10.921 | 33.5 |
| Diesel HDS Stab Reboiler | 519,526 | 5,414,631 | -122.661 | -10.920 | 33.2 |
| South Dock Combustor | 517,800 | 5,412,058 | -124.388 | -13.366 | 16.7 |
| Reforming Furnace #1 (North H2 Plant, Stack 1) | 519,577 | 5,414,803 | -122.608 | -10.754 | 33.8 |
| Reforming Furnace #1 (North H2 Plant, Stack 2) | 519,577 | 5,414,795 | -122.608 | -10.762 | 33.8 |
| Reforming Furnace #2 (South H2 Plant, Stack 1) | 519,577 | 5,414,758 | -122.609 | -10.798 | 33.8 |
| Reforming Furnace #2 (South H2 Plant, Stack 2) | 519,577 | 5,414,750 | -122.609 | -10.806 | 33.7 |
| Naphtha HDS Stripper Reboiler | 519,431 | 5,414,537 | -122.755 | -11.008 | 32.3 |
| High Pressure Flare | 518,840 | 5,414,683 | -123.321 | -10.853 | 28.1 |
| 1st Stage HCR Frac Reboiler | 519,307 | 5,414,715 | -122.870 | -10.833 | 31.7 |
| 2nd Stage HCR Frac Reboiler | 519,307 | 5,414,698 | -122.871 | -10.849 | 31.6 |
| R-1 HCR Reactor Heater | 519,312 | 5,414,790 | -122.864 | -10.761 | 31.8 |
| R-4 HCR Reactor Heater | 519,312 | 5,414,777 | -122.864 | -10.773 | 31.8 |
| Low Pressure Flare | 518,931 | 5,414,683 | -123.233 | -10.855 | 28.8 |
| Naphtha HDS Charge Heater | 519,444 | 5,414,537 | -122.742 | -11.008 | 32.4 |
| #1 Reformer Heaters - 1 & 2 | 519,399 | 5,414,543 | -122.786 | -11.002 | 32.1 |
| #1 Reformer Heaters - 3 & 4 | 519,389 | 5,414,543 | -122.795 | -11.001 | 32.0 |
| SRU and TGU | 519,265 | 5,414,680 | -122.911 | -10.866 | 31.3 |
| South Vacuum Heater | 519,634 | 5,414,627 | -122.557 | -10.926 | 34.0 |

1. Lambert conformal conic coordinates with an origin of (49N, 121W)
2. UTM coordinates, zone 10, NAD27 datum
3. Calculated using bilinear interpolation from the 4-km mesh size terrain grid used in the CALPUFF simulations

# TABLE 3-4

## BASELINE AND BART STACK PARAMETERS

| Source Name | Height (ft) | Diam. (ft) | Temp. (F) | Flow (acfm) |
|---|---|---|---|---|
| Coker Charge Heater (#1 North) | 175.5 | 8.7 | 531.3 | 43,342 |
| Coker Charge Heater (#2 South) | 175.5 | 8.3 | 543.8 | 44,747 |
| Crude Heater | 198.1 | 11.9 | 435.5 | 146,147 |
| Diesel HDS Charge Heater | 134.6 | 3.8 | 606.7 | 1,678 |
| Diesel HDS Stab Reboiler | 102.7 | 4.4 | 799.7 | 15,424 |
| South Dock Combustor | 98.0 | 12.6 | 1,400.0 | 145,700 |
| Reforming Furnace #1 (North H2 Plant, Stack 1) | 86.5 | 5.7 | 593.6 | 77,430 |
| Reforming Furnace #1 (North H2 Plant, Stack 2) | 86.5 | 5.7 | 578.5 | 77,430 |
| Reforming Furnace #2 (South H2 Plant, Stack 1) | 86.5 | 5.7 | 582.0 | 79,256 |
| Reforming Furnace #2 (South H2 Plant, Stack 2) | 86.5 | 5.7 | 653.5 | 79,256 |
| Naphtha HDS Stripper Reboiler | 100.9 | 5.0 | 694.8 | 13,285 |
| High Pressure Flare | 229.2 | 2.0 | 1,831.7 | 19,224 |
| 1st Stage HCR Frac Reboiler | 160.8 | 10.6 | 276.2 | 37,734 |
| 2nd Stage HCR Frac Reboiler | 155.3 | 9.4 | 299.6 | 48,744 |
| R-1 HCR Reactor Heater | 141.7 | 6.6 | 776.0 | 19,859 |
| R-4 HCR Reactor Heater | 150.2 | 3.5 | 957.9 | 15,721 |
| Low Pressure Flare | 229.7 | 2.0 | 1,831.7 | 19,224 |
| Naphtha HDS Charge Heater | 100.7 | 6.1 | 796.9 | 16,065 |
| #1 Reformer Heaters - 1 & 2 | 200.3 | 10.2 | 652.4 | 175,958 |
| #1 Reformer Heaters - 3 & 4 | 200.3 | 10.2 | 648.8 | 175,958 |
| SRU and TGU | 300.7 | 3.4 | 550.1 | 36,183 |
| South Vacuum Heater | 160.5 | 8.1 | 411.8 | 34,496 |

# TABLE 4-1

## BASELINE AND BART CASE $PM_{10}$ SPECIATION

| Source Name | SCC [1] | $PM_{2.5}$ to $PM_{10}$ Ratio | $PM_{2.5}$ Fraction | | | | |
|---|---|---|---|---|---|---|---|
| | | | EC | PMF | $NH_4NO_3$ [2] | OC | $(NH_4)_2SO_4$ [3] |
| Coker Charge Heater (#1 North) | 30600106 | 0.985 | 0.000 | 0.441 | 0.006 | 0.084 | 0.470 |
| Coker Charge Heater (#2 South) | 30600106 | 0.985 | 0.000 | 0.441 | 0.006 | 0.084 | 0.470 |
| Crude Heater | 30600106 | 0.985 | 0.000 | 0.441 | 0.006 | 0.084 | 0.470 |
| Diesel HDS Charge Heater | 30600106 | 0.985 | 0.000 | 0.441 | 0.006 | 0.084 | 0.470 |
| Diesel HDS Stab Reboiler | 30600106 | 0.985 | 0.000 | 0.441 | 0.006 | 0.084 | 0.470 |
| South Dock Combustor | 30609904 | 1.000 | 0.000 | 0.195 | 0.006 | 0.600 | 0.200 |
| Reforming Furnace #1 (North H2 Plant, Stack 1) | 30600106 | 0.985 | 0.000 | 0.441 | 0.006 | 0.084 | 0.470 |
| Reforming Furnace #1 (North H2 Plant, Stack 2) | 30600106 | 0.985 | 0.000 | 0.441 | 0.006 | 0.084 | 0.470 |
| Reforming Furnace #2 (South H2 Plant, Stack 1) | 30600106 | 0.985 | 0.000 | 0.441 | 0.006 | 0.084 | 0.470 |
| Reforming Furnace #2 (South H2 Plant, Stack 2) | 30600106 | 0.985 | 0.000 | 0.441 | 0.006 | 0.084 | 0.470 |
| Naphtha HDS Stripper Reboiler | 30600106 | 0.985 | 0.000 | 0.441 | 0.006 | 0.084 | 0.470 |
| High Pressure Flare | 30600904 | 1.000 | 0.000 | 0.000 | 0.000 | 1.000 | 0.000 |
| 1st Stage HCR Frac Reboiler | 30600106 | 0.985 | 0.000 | 0.441 | 0.006 | 0.084 | 0.470 |
| 2nd Stage HCR Frac Reboiler | 30600106 | 0.985 | 0.000 | 0.441 | 0.006 | 0.084 | 0.470 |
| R-1 HCR Reactor Heater | 30600106 | 0.985 | 0.000 | 0.441 | 0.006 | 0.084 | 0.470 |
| R-4 HCR Reactor Heater | 30600106 | 0.985 | 0.000 | 0.441 | 0.006 | 0.084 | 0.470 |
| Low Pressure Flare | 30600904 | 1.000 | 0.000 | 0.000 | 0.000 | 1.000 | 0.000 |
| Naphtha HDS Charge Heater | 30600106 | 0.985 | 0.000 | 0.441 | 0.006 | 0.084 | 0.470 |
| #1 Reformer Heaters - 1 & 2 | 30600106 | 0.985 | 0.000 | 0.441 | 0.006 | 0.084 | 0.470 |
| #1 Reformer Heaters - 3 & 4 | 30600106 | 0.985 | 0.000 | 0.441 | 0.006 | 0.084 | 0.470 |
| SRU and TGU | 30603301 | 1.000 | 0.000 | 0.720 | 0.003 | 0.042 | 0.235 |
| South Vacuum Heater | 30600106 | 0.985 | 0.000 | 0.441 | 0.006 | 0.084 | 0.470 |

1. SCC Codes are as follows: 30600106 - Petroleum Industry Process Gas-Fired Process Heater, 30600904 - Petroleum Industry Process Gas-Fired Flare, 30603301 - Petroleum Industry SRU and 30609904 - Petroleum Industry Process Gas Incinerator
2. Ammonium nitrate. Nitrate ($NO_3$) is the actual emitted species used by CALPUFF
3. Ammonium sulfate. Sulfate ($SO_4$) is the actual emitted species used by CALPUFF

## TABLE 4-2

## CALPUFF EMISSION RATES FOR BASELINE CASE (LB/HR)

| Source Name | ns [1] | $SO_2$ | $SO_4$ | NOx | $HNO_3$ | $NO_3$ | EC | SOA (OC) [2] | PMF | PMC |
|---|---|---|---|---|---|---|---|---|---|---|
| Coker Charge Heater (#1 North) (#2 South) | 2 | 15.76 | 0.90 | 17.88 | 0.00 | 0.01 | 0.00 | 0.22 | 1.16 | 0.04 |
| Reforming Furnace #1 (North H2 Plant) | 2 | 11.22 | 0.96 | 30.15 | 0.00 | 0.01 | 0.00 | 0.24 | 1.24 | 0.04 |
| Reforming Furnace #2 (South H2 Plant) | 2 | 11.00 | 0.94 | 29.58 | 0.00 | 0.01 | 0.00 | 0.23 | 1.22 | 0.04 |
| 1st & 2nd Stage HCR Frac Reboilers | 2 | 11.57 | 0.99 | 34.18 | 0.00 | 0.01 | 0.00 | 0.24 | 1.28 | 0.04 |
| R-1 & R-4 HCR Reactor Heaters | 2 | 4.78 | 0.41 | 12.86 | 0.00 | 0.01 | 0.00 | 0.10 | 0.53 | 0.02 |
| #1 Reformer Heaters | 2 | 25.86 | 2.22 | 106.41 | 0.00 | 0.03 | 0.00 | 0.54 | 2.86 | 0.10 |
| Low & High Pressure Flares | 2 | 7.33 | 0.00 | 6.37 | 0.00 | 0.00 | 0.00 | 0.72 | 0.00 | 0.00 |
| Crude Heater | 1 | 20.03 | 1.85 | 109.75 | 0.00 | 0.02 | 0.00 | 0.46 | 2.39 | 0.08 |
| South Dock Combustor | 1 | 0.00 | 0.00 | 6.62 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Naphtha HDS Charge Heater | 1 | 3.86 | 0.33 | 10.39 | 0.00 | 0.00 | 0.00 | 0.08 | 0.43 | 0.01 |
| SRU and TGU | 1 | 8.53 | 0.04 | 1.37 | 0.00 | 0.00 | 0.00 | 0.01 | 0.16 | 0.00 |
| South Vacuum Heater | 1 | 7.69 | 0.58 | 7.26 | 0.00 | 0.01 | 0.00 | 0.14 | 0.75 | 0.03 |
| Diesel HDS Charge Heater - Diesel HDS Stab Reboiler - Naphtha HDS Stripper Reboiler | 3 | 5.60 | 0.48 | 15.06 | 0.00 | 0.01 | 0.00 | 0.12 | 0.62 | 0.02 |
| | Total | 133.25 | 9.71 | 387.88 | 0.00 | 0.12 | 0.00 | 3.11 | 12.63 | 0.44 |

1. Number of combined stacks simulated as a single stack
2. OC emissions were actually labeled secondary organic aerosols (SOA) in the CALPUFF input files to facilitate post-processing with CALPOST. This assumes all OC emitted forms SOA with the same molecular weight

**TABLE 4-3**

**CALPUFF EMISSION RATES FOR BART CASE (LB/HR)**

| Source Name | ns [1] | $SO_2$ | $SO_4$ | NOx | $HNO_3$ | $NO_3$ | EC | SOA (OC) [1] | PMF | PMC |
|---|---|---|---|---|---|---|---|---|---|---|
| Coker Charge Heater (#1 North) (#2 South) | 2 | 15.76 | 0.90 | 17.88 | 0.00 | 0.01 | 0.00 | 0.22 | 1.16 | 0.04 |
| Reforming Furnace #1 (North H2 Plant) | 2 | 11.22 | 0.96 | 30.15 | 0.00 | 0.01 | 0.00 | 0.24 | 1.24 | 0.04 |
| Reforming Furnace #2 (South H2 Plant) | 2 | 11.00 | 0.94 | 29.58 | 0.00 | 0.01 | 0.00 | 0.23 | 1.22 | 0.04 |
| 1st & 2nd Stage HCR Frac Reboilers | 2 | 11.57 | 0.99 | 16.89 | 0.00 | 0.01 | 0.00 | 0.24 | 1.28 | 0.04 |
| R-1 & R-4 HCR Reactor Heaters | 2 | 4.78 | 0.41 | 5.90 | 0.00 | 0.01 | 0.00 | 0.10 | 0.53 | 0.02 |
| #1 Reformer Heaters | 2 | 25.86 | 2.22 | 106.41 | 0.00 | 0.03 | 0.00 | 0.54 | 2.86 | 0.10 |
| Low & High Pressure Flares | 2 | 7.33 | 0.00 | 6.37 | 0.00 | 0.00 | 0.00 | 0.72 | 0.00 | 0.00 |
| Crude Heater | 1 | 20.03 | 1.85 | 109.75 | 0.00 | 0.02 | 0.00 | 0.46 | 2.39 | 0.08 |
| South Dock Combustor | 1 | 0.00 | 0.00 | 6.62 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Naphtha HDS Charge Heater | 1 | 3.86 | 0.33 | 10.39 | 0.00 | 0.00 | 0.00 | 0.08 | 0.43 | 0.01 |
| SRU and TGU | 1 | 8.53 | 0.04 | 1.37 | 0.00 | 0.00 | 0.00 | 0.01 | 0.16 | 0.00 |
| South Vacuum Heater | 1 | 7.69 | 0.58 | 7.26 | 0.00 | 0.01 | 0.00 | 0.14 | 0.75 | 0.03 |
| Diesel HDS Charge Heater - Diesel HDS Stab Reboiler - Naphtha HDS Stripper Reboiler | 3 | 5.60 | 0.48 | 8.89 | 0.00 | 0.01 | 0.00 | 0.12 | 0.62 | 0.02 |
| | Total | 133.25 | 9.71 | 357.46 | 0.00 | 0.12 | 0.00 | 3.11 | 12.63 | 0.44 |

1. Number of combined stacks simulated as a single stack
2. OC emissions were actually labeled secondary organic aerosols (SOA) in the CALPUFF input files to facilitate post-processing with CALPOST. This assumes all OC emitted forms SOA with the same molecular weight

**TABLE 5-1**

**NUMBER OF DAYS WITH PREDICTED CHANGE TO THE HAZE INDEX GREATER THAN 0.5 DECIVIEWS**

| Area of Interest | Period | Number of Days in 2003-2005 with Delta HI > 0.5 dv | | |
|---|---|---|---|---|
| | | Baseline | BART | Reduction (%) |
| Alpine Lakes Wilderness | 2003-2005 | 7 | 5 | 29% |
| Glacier Peak Wilderness | 2003-2005 | 0 | 0 | 0% |
| Goat Rocks Wilderness | 2003-2005 | 1 | 1 | 0% |
| Mt. Adams Wilderness | 2003-2005 | 0 | 0 | 0% |
| Mt. Rainier National Park | 2003-2005 | 3 | 3 | 0% |
| N. Cascades National Park | 2003-2005 | 5 | 1 | 80% |
| Olympic National Park | 2003-2005 | 57 | 53 | 7% |
| Pasayten Wilderness | 2003-2005 | 0 | 0 | 0% |
| Overall | Min | 0 | 0 | |
| | Mean | 9 | 8 | |
| | Max | 57 | 53 | |

**TABLE 5-2**

**THREE-YEAR PREDICTED 98TH PERCENTILE CHANGE TO THE DAILY HAZE INDEX**

| Area of Interest | Period | 98th Percentile Delta HI (dv) [1] | | |
|---|---|---|---|---|
| | | Baseline | BART | Reduction |
| Alpine Lakes Wilderness | 2003-2005 | 0.260 | 0.244 | 6% |
| Glacier Peak Wilderness | 2003-2005 | 0.248 | 0.233 | 6% |
| Goat Rocks Wilderness | 2003-2005 | 0.110 | 0.103 | 6% |
| Mt. Adams Wilderness | 2003-2005 | 0.082 | 0.078 | 5% |
| Mt. Rainier National Park | 2003-2005 | 0.222 | 0.212 | 5% |
| N. Cascades National Park | 2003-2005 | 0.365 | 0.343 | 6% |
| Olympic National Park | 2003-2005 | 0.842 | 0.786 | 7% |
| Pasayten Wilderness | 2003-2005 | 0.196 | 0.185 | 6% |
| Overall | Min | 0.082 | 0.078 | |
| | Mean | 0.291 | 0.273 | |
| | Max | 0.842 | 0.786 | |

1. Based on the 22nd highest value for each Class I area.

**TABLE 5-3**

**PREDICTED 98TH PERCENTILE CHANGE TO THE DAILY HAZE INDEX BY YEAR**

| Area of Interest | Year | 98th Percentile Delta HI (dv) [1] | | |
|---|---|---|---|---|
| | | Baseline | BART | Reduction (%) |
| Alpine Lakes Wilderness | 2003 | 0.294 | 0.277 | 6% |
| | 2004 | 0.271 | 0.255 | 6% |
| | 2005 | 0.211 | 0.200 | 5% |
| Glacier Peak Wilderness | 2003 | 0.290 | 0.280 | 3% |
| | 2004 | 0.238 | 0.228 | 4% |
| | 2005 | 0.204 | 0.194 | 5% |
| Goat Rocks Wilderness | 2003 | 0.117 | 0.111 | 5% |
| | 2004 | 0.122 | 0.117 | 4% |
| | 2005 | 0.091 | 0.087 | 4% |
| Mt. Adams Wilderness | 2003 | 0.083 | 0.078 | 6% |
| | 2004 | 0.080 | 0.075 | 6% |
| | 2005 | 0.070 | 0.064 | 9% |
| Mt. Rainier National Park | 2003 | 0.238 | 0.224 | 6% |
| | 2004 | 0.279 | 0.266 | 5% |
| | 2005 | 0.181 | 0.171 | 6% |
| N. Cascades National Park | 2003 | 0.367 | 0.348 | 5% |
| | 2004 | 0.370 | 0.354 | 4% |
| | 2005 | 0.286 | 0.271 | 5% |
| Olympic National Park | 2003 | 0.842 | 0.780 | 7% |
| | 2004 | 0.762 | 0.706 | 7% |
| | 2005 | 0.901 | 0.832 | 8% |
| Pasayten Wilderness | 2003 | 0.181 | 0.171 | 6% |
| | 2004 | 0.215 | 0.202 | 6% |
| | 2005 | 0.176 | 0.167 | 5% |
| Overall | Min | 0.070 | 0.064 | |
| | Mean | 0.286 | 0.269 | |
| | Max | 0.901 | 0.832 | |

1. Based on the 8th highest on a Class I area basis

# TABLE 5-4

## AVERAGE EXTINCTION BUDGETS FOR TOP 98TH PERCENTILE DAYS BASELINE CASE

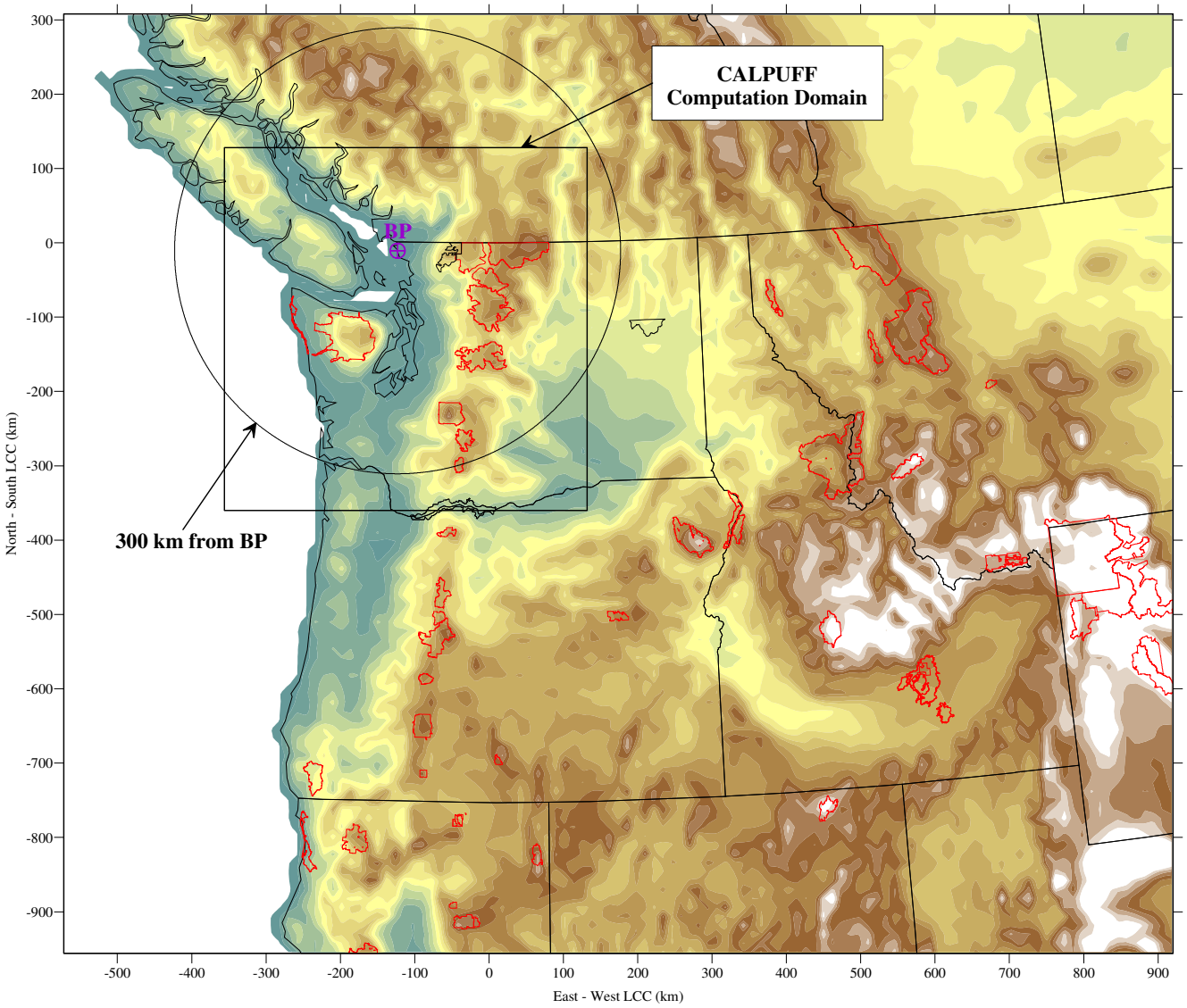
| Area of Interest | Year | Contribution by Species (%) | | | | | |
|---|---|---|---|---|---|---|---|
| | | $(NH_4)_2SO_4$ | $NH_4NO_3$ | OC | EC | PMC | PMF |
| Alpine Lakes Wilderness | 2003 | 23.6 | 75.3 | 0.6 | 0.0 | 0.0 | 0.6 |
| | 2004 | 26.6 | 72.1 | 0.6 | 0.0 | 0.0 | 0.6 |
| | 2005 | 24.4 | 74.2 | 0.7 | 0.0 | 0.0 | 0.7 |
| | 2003-2005 | 25.3 | 73.3 | 0.6 | 0.0 | 0.0 | 0.7 |
| Glacier Peak Wilderness | 2003 | 30.2 | 68.1 | 0.8 | 0.0 | 0.0 | 0.8 |
| | 2004 | 28.5 | 69.8 | 0.8 | 0.0 | 0.0 | 0.9 |
| | 2005 | 23.4 | 75.0 | 0.8 | 0.0 | 0.0 | 0.8 |
| | 2003-2005 | 27.8 | 70.7 | 0.8 | 0.0 | 0.0 | 0.8 |
| Goat Rocks Wilderness | 2003 | 26.8 | 72.2 | 0.5 | 0.0 | 0.0 | 0.5 |
| | 2004 | 30.3 | 68.6 | 0.6 | 0.0 | 0.0 | 0.6 |
| | 2005 | 24.1 | 74.9 | 0.5 | 0.0 | 0.0 | 0.5 |
| | 2003-2005 | 27.2 | 71.7 | 0.5 | 0.0 | 0.0 | 0.5 |
| Mt. Adams Wilderness | 2003 | 28.0 | 71.0 | 0.5 | 0.0 | 0.0 | 0.5 |
| | 2004 | 30.6 | 68.2 | 0.6 | 0.0 | 0.0 | 0.6 |
| | 2005 | 24.8 | 74.2 | 0.5 | 0.0 | 0.0 | 0.5 |
| | 2003-2005 | 28.3 | 70.6 | 0.5 | 0.0 | 0.0 | 0.5 |
| Mt. Rainier National Park | 2003 | 24.5 | 74.5 | 0.5 | 0.0 | 0.0 | 0.5 |
| | 2004 | 26.8 | 72.2 | 0.5 | 0.0 | 0.0 | 0.5 |
| | 2005 | 23.4 | 75.3 | 0.6 | 0.0 | 0.0 | 0.6 |
| | 2003-2005 | 25.7 | 73.3 | 0.5 | 0.0 | 0.0 | 0.5 |
| N. Cascades National Park | 2003 | 24.4 | 74.1 | 0.7 | 0.0 | 0.0 | 0.7 |
| | 2004 | 26.0 | 72.5 | 0.7 | 0.0 | 0.0 | 0.7 |
| | 2005 | 26.3 | 72.1 | 0.8 | 0.0 | 0.0 | 0.8 |
| | 2003-2005 | 26.0 | 72.5 | 0.7 | 0.0 | 0.0 | 0.7 |
| Olympic National Park | 2003 | 23.0 | 75.9 | 0.5 | 0.0 | 0.0 | 0.5 |
| | 2004 | 20.5 | 78.4 | 0.5 | 0.0 | 0.0 | 0.5 |
| | 2005 | 19.2 | 79.7 | 0.5 | 0.0 | 0.0 | 0.5 |
| | 2003-2005 | 20.5 | 78.4 | 0.5 | 0.0 | 0.0 | 0.5 |
| Pasayten Wilderness | 2003 | 27.3 | 71.1 | 0.8 | 0.0 | 0.0 | 0.8 |
| | 2004 | 27.5 | 71.0 | 0.8 | 0.0 | 0.0 | 0.8 |
| | 2005 | 26.0 | 72.5 | 0.7 | 0.0 | 0.0 | 0.8 |
| | 2003-2005 | 27.6 | 70.9 | 0.7 | 0.0 | 0.0 | 0.7 |
| Overall | Min | 19.2 | 68.1 | 0.5 | 0.0 | 0.0 | 0.5 |
| | Mean | 25.8 | 73.0 | 0.6 | 0.0 | 0.0 | 0.6 |
| | Max | 30.6 | 79.7 | 0.8 | 0.0 | 0.0 | 0.9 |

# TABLE 5-5

## AVERAGE EXTINCTION BUDGETS FOR TOP 98TH PERCENTILE DAYS BART CASE

| Area of Interest | Year | Contribution by Species (%) | | | | | |
|---|---|---|---|---|---|---|---|
| | | $(NH_4)_2SO_4$ | $NH_4NO_3$ | OC | EC | PMC | PMF |
| Alpine Lakes Wilderness | 2003 | 25.0 | 73.8 | 0.6 | 0.0 | 0.0 | 0.6 |
| | 2004 | 28.2 | 70.5 | 0.6 | 0.0 | 0.0 | 0.6 |
| | 2005 | 27.3 | 71.2 | 0.7 | 0.0 | 0.0 | 0.8 |
| | 2003-2005 | 27.0 | 71.7 | 0.7 | 0.0 | 0.0 | 0.7 |
| Glacier Peak Wilderness | 2003 | 31.7 | 66.5 | 0.9 | 0.0 | 0.0 | 0.9 |
| | 2004 | 30.1 | 68.1 | 0.9 | 0.0 | 0.0 | 0.9 |
| | 2005 | 26.2 | 72.1 | 0.8 | 0.0 | 0.0 | 0.9 |
| | 2003-2005 | 29.3 | 69.1 | 0.8 | 0.0 | 0.0 | 0.8 |
| Goat Rocks Wilderness | 2003 | 28.5 | 70.4 | 0.5 | 0.0 | 0.0 | 0.6 |
| | 2004 | 31.8 | 66.9 | 0.6 | 0.0 | 0.0 | 0.6 |
| | 2005 | 25.5 | 73.4 | 0.5 | 0.0 | 0.0 | 0.5 |
| | 2003-2005 | 30.0 | 68.8 | 0.6 | 0.0 | 0.0 | 0.6 |
| Mt. Adams Wilderness | 2003 | 30.0 | 69.0 | 0.5 | 0.0 | 0.0 | 0.5 |
| | 2004 | 32.2 | 66.6 | 0.6 | 0.0 | 0.0 | 0.6 |
| | 2005 | 27.7 | 71.2 | 0.5 | 0.0 | 0.0 | 0.6 |
| | 2003-2005 | 30.0 | 68.8 | 0.6 | 0.0 | 0.0 | 0.6 |
| Mt. Rainier National Park | 2003 | 26.2 | 72.8 | 0.5 | 0.0 | 0.0 | 0.5 |
| | 2004 | 28.3 | 70.6 | 0.5 | 0.0 | 0.0 | 0.5 |
| | 2005 | 24.7 | 74.0 | 0.6 | 0.0 | 0.0 | 0.7 |
| | 2003-2005 | 27.3 | 71.6 | 0.5 | 0.0 | 0.0 | 0.6 |
| N. Cascades National Park | 2003 | 27.6 | 70.8 | 0.8 | 0.0 | 0.0 | 0.8 |
| | 2004 | 27.6 | 70.9 | 0.8 | 0.0 | 0.0 | 0.8 |
| | 2005 | 27.8 | 70.5 | 0.8 | 0.0 | 0.0 | 0.8 |
| | 2003-2005 | 27.6 | 70.8 | 0.8 | 0.0 | 0.0 | 0.8 |
| Olympic National Park | 2003 | 24.6 | 74.3 | 0.6 | 0.0 | 0.0 | 0.6 |
| | 2004 | 22.0 | 76.9 | 0.6 | 0.0 | 0.0 | 0.6 |
| | 2005 | 20.6 | 78.2 | 0.6 | 0.0 | 0.0 | 0.6 |
| | 2003-2005 | 22.9 | 75.9 | 0.6 | 0.0 | 0.0 | 0.6 |
| Pasayten Wilderness | 2003 | 28.9 | 69.5 | 0.8 | 0.0 | 0.0 | 0.8 |
| | 2004 | 29.0 | 69.3 | 0.8 | 0.0 | 0.0 | 0.8 |
| | 2005 | 27.5 | 70.9 | 0.8 | 0.0 | 0.0 | 0.8 |
| | 2003-2005 | 29.2 | 69.2 | 0.8 | 0.0 | 0.0 | 0.8 |
| Overall | Min | 20.6 | 66.5 | 0.5 | 0.0 | 0.0 | 0.5 |
| | Mean | 27.6 | 71.1 | 0.7 | 0.0 | 0.0 | 0.7 |
| | Max | 32.2 | 78.2 | 0.9 | 0.0 | 0.0 | 0.9 |

# FIGURES

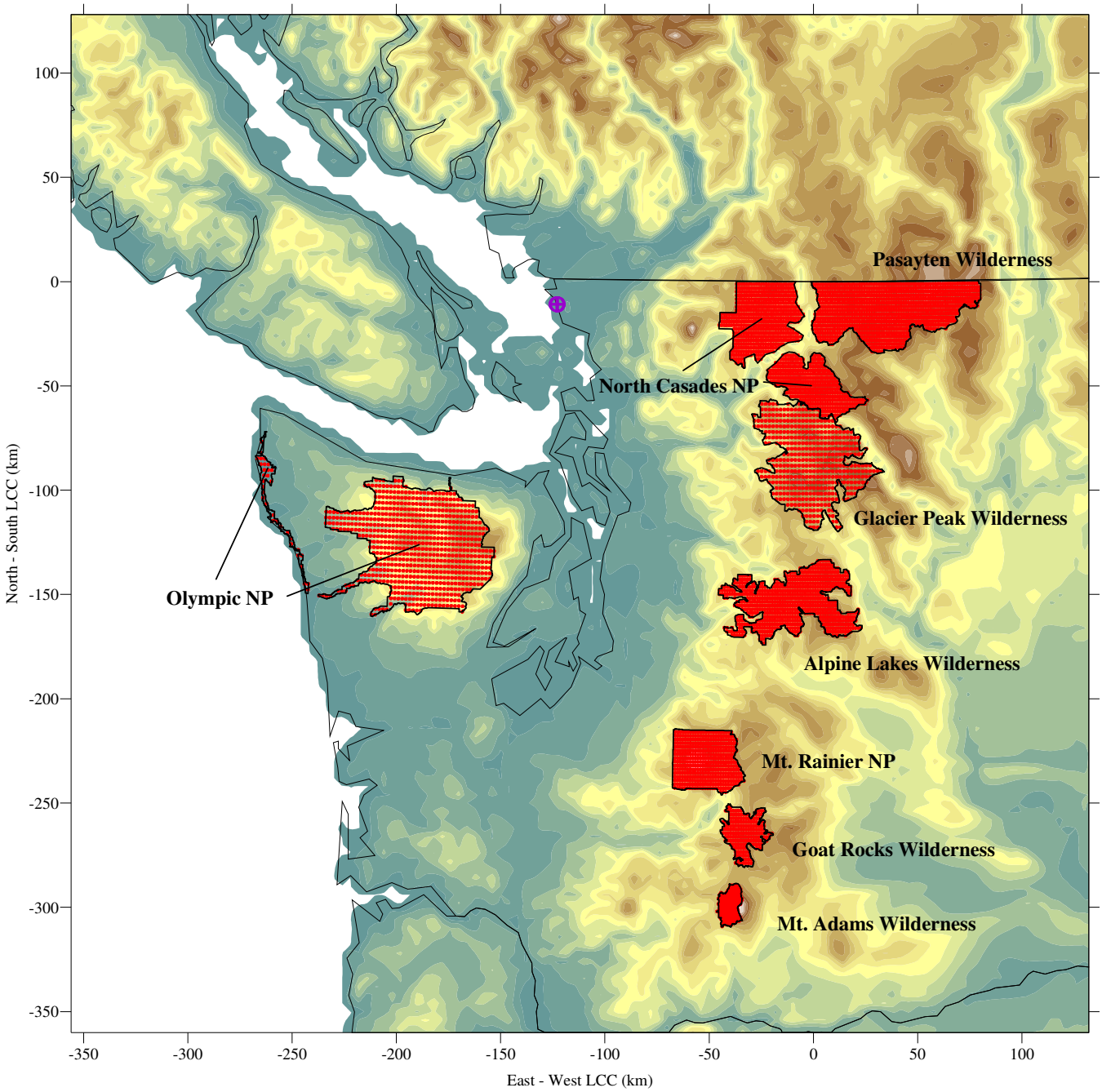



GEOMATRIX

CALMET AND CALPUFF MODELING DOMAINS
BP Cherry Point Refinery BART Determination Modeling
Blaine, Washington

Project No.
12966.000

Figure
**4-1**

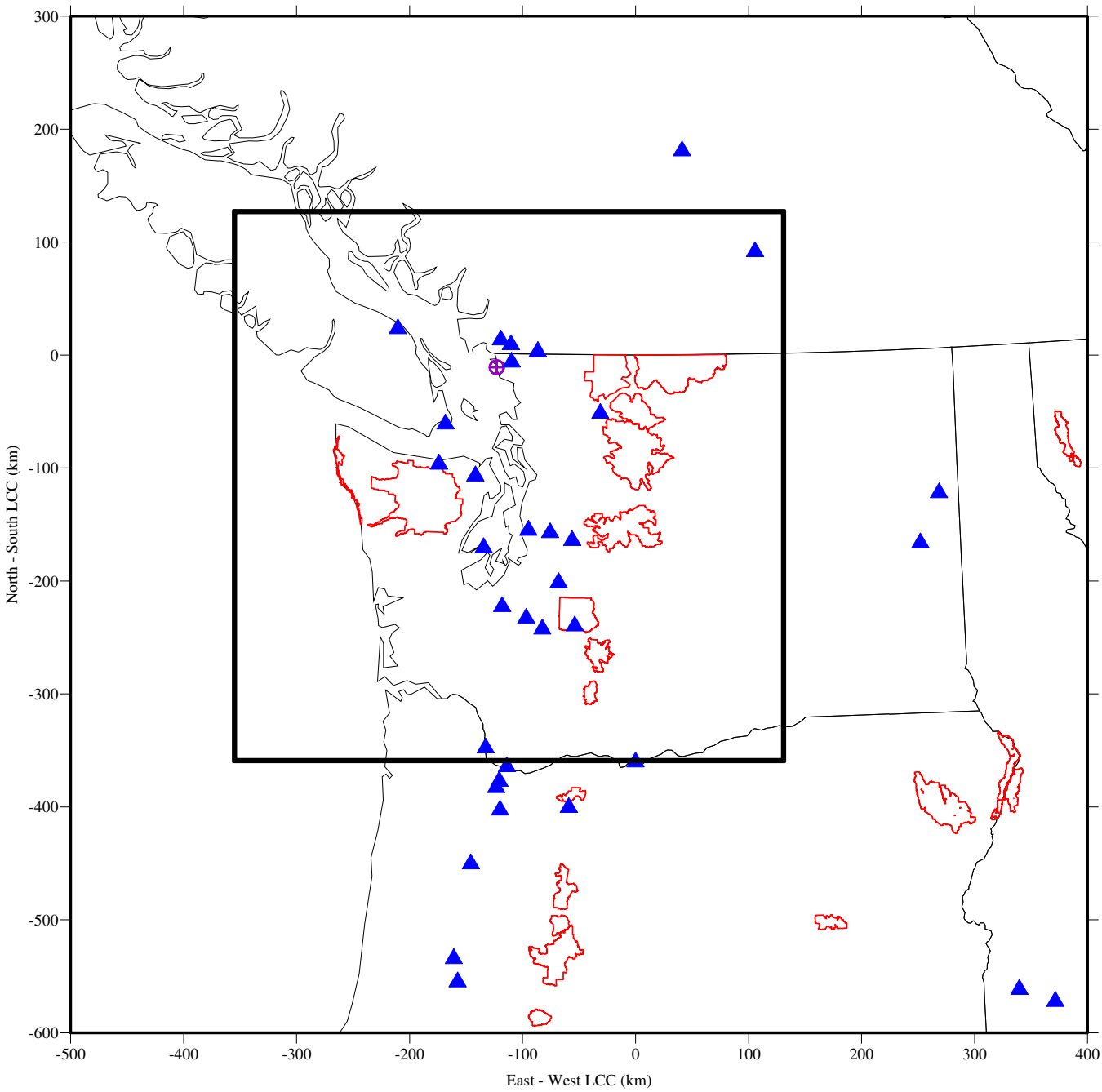



GEOMATRIX

CALPUFF MODELING DOMAIN WITH CLASS I RECEPTORS
BP Cherry Point Refinery BART Determination Modeling
Blaine, Washington

Project No.
12966.000

Figure
**4-2**

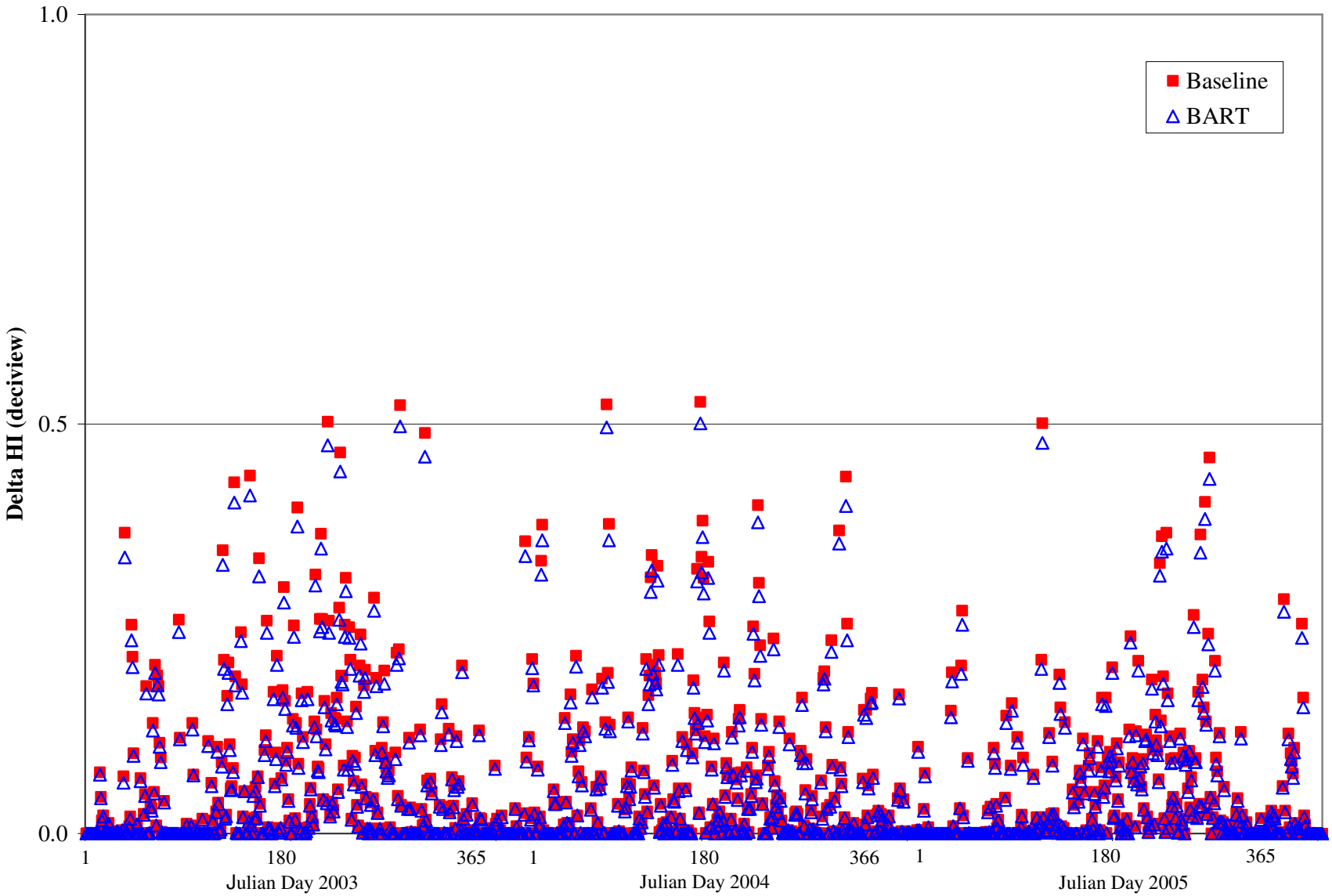



GEOMATRIX

OZONE STATIONS NEAR DOMAIN
BP Cherry Point Refinery BART Determination Modeling
Blaine, Washington

Project No.
12966.000.0

Figure
**4-3**

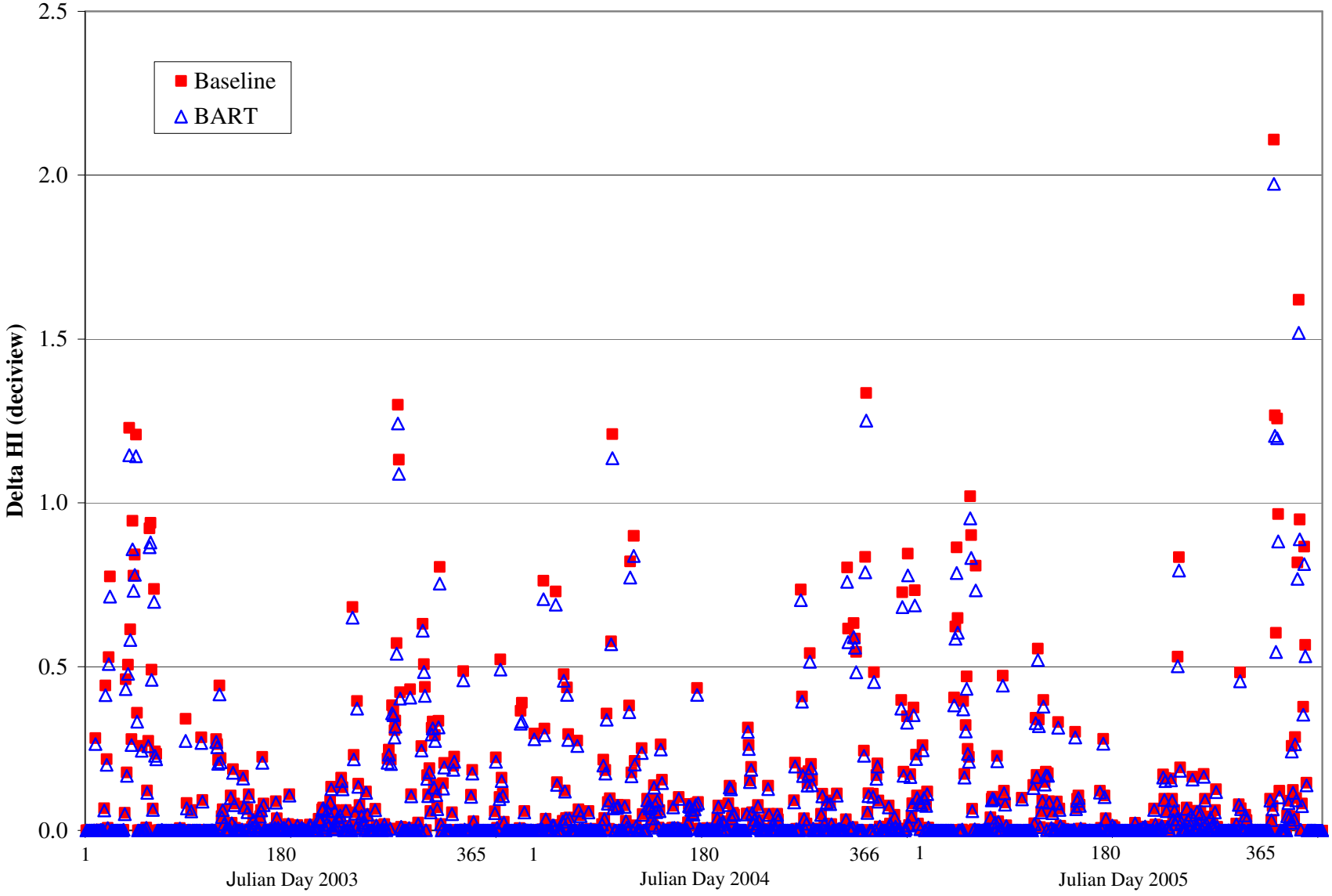



GEOMATRIX

TIME SERIES OF MAXIMUM DAILY DELTA HAZE INDEX FOR NORTH CASCADES NATIONAL PARK
BASELINE VERSUS BART CASES
BP Cherry Point Refinery BART Determination Modeling
Blaine, Washington

Project No.
12966.000

Figure
**5-1**

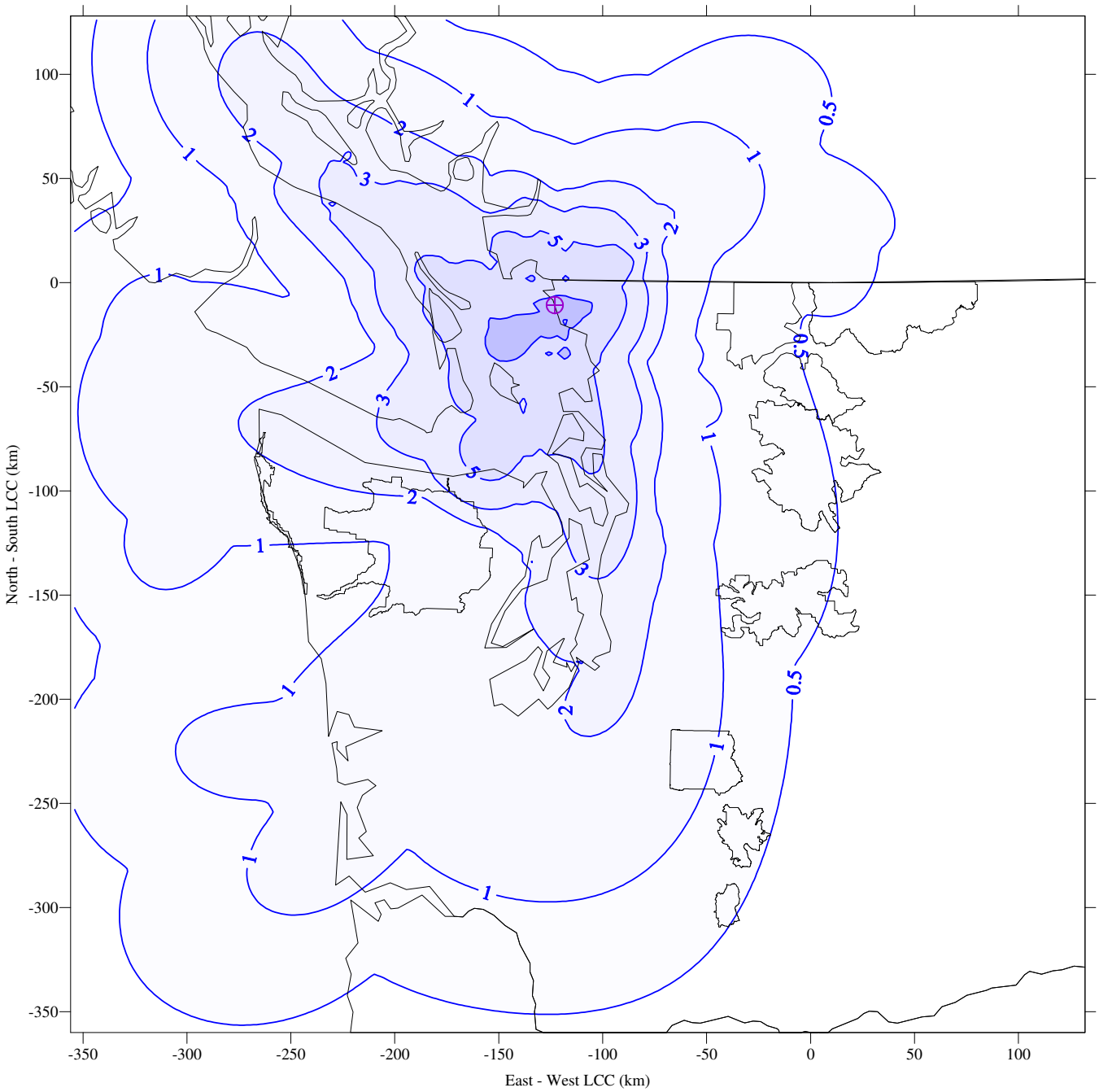



GEOMATRIX

TIME SERIES OF MAXIMUM DAILY DELTA HAZE INDEX FOR OLYMPIC NATIONAL PARK
BASELINE VERSUS BART CASES
BP Cherry Point Refinery BART Determination Modeling
Blaine, Washington

Project No.
12966.000

Figure
**5-2**

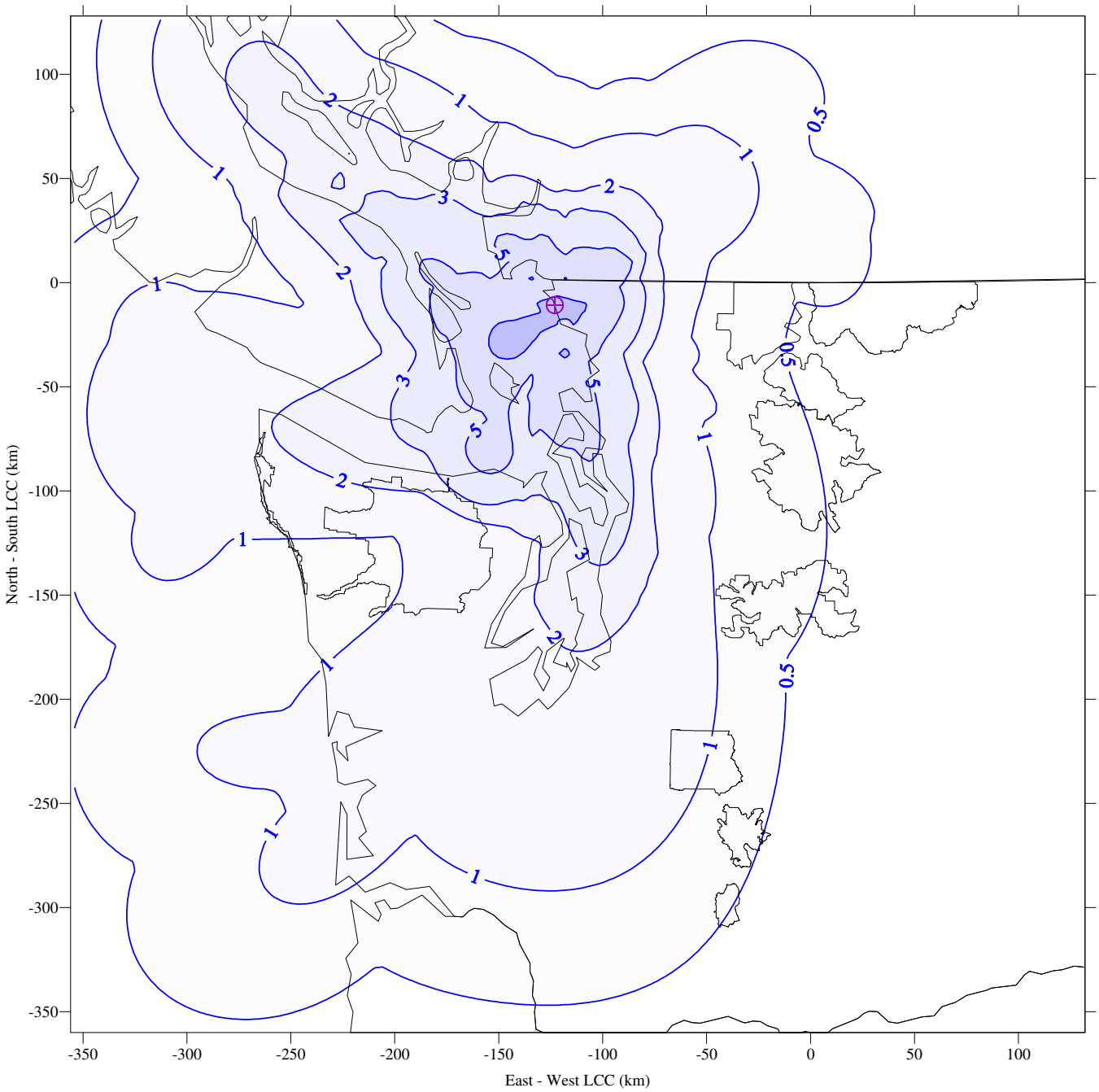



GEOMATRIX

BASELINE CASE MAXIMUM 24-HOUR EXTINCTION (1/MM) 2003-2005
BP Cherry Point Refinery BART Determination Modeling
Blaine, Washington

Project No.
12966.000

Figure
**5-3**

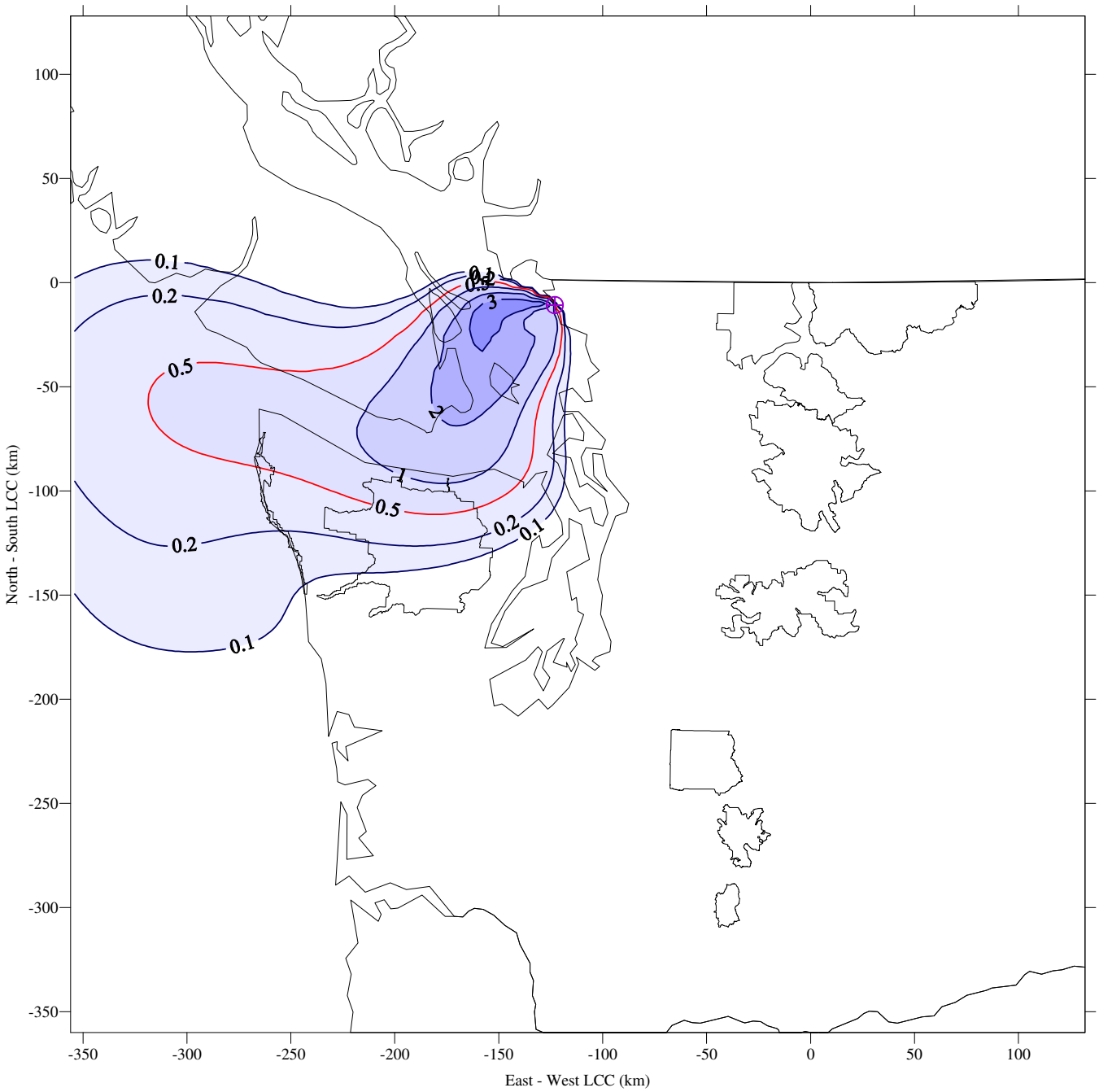



GEOMATRIX

BART CASE MAXIMUM 24-HOUR EXTINCTION (1/MM) 2003-2005
BP Cherry Point Refinery BART Determination Modeling
Blaine, Washington

Project No.
12966.000.0

Figure
**5-4**

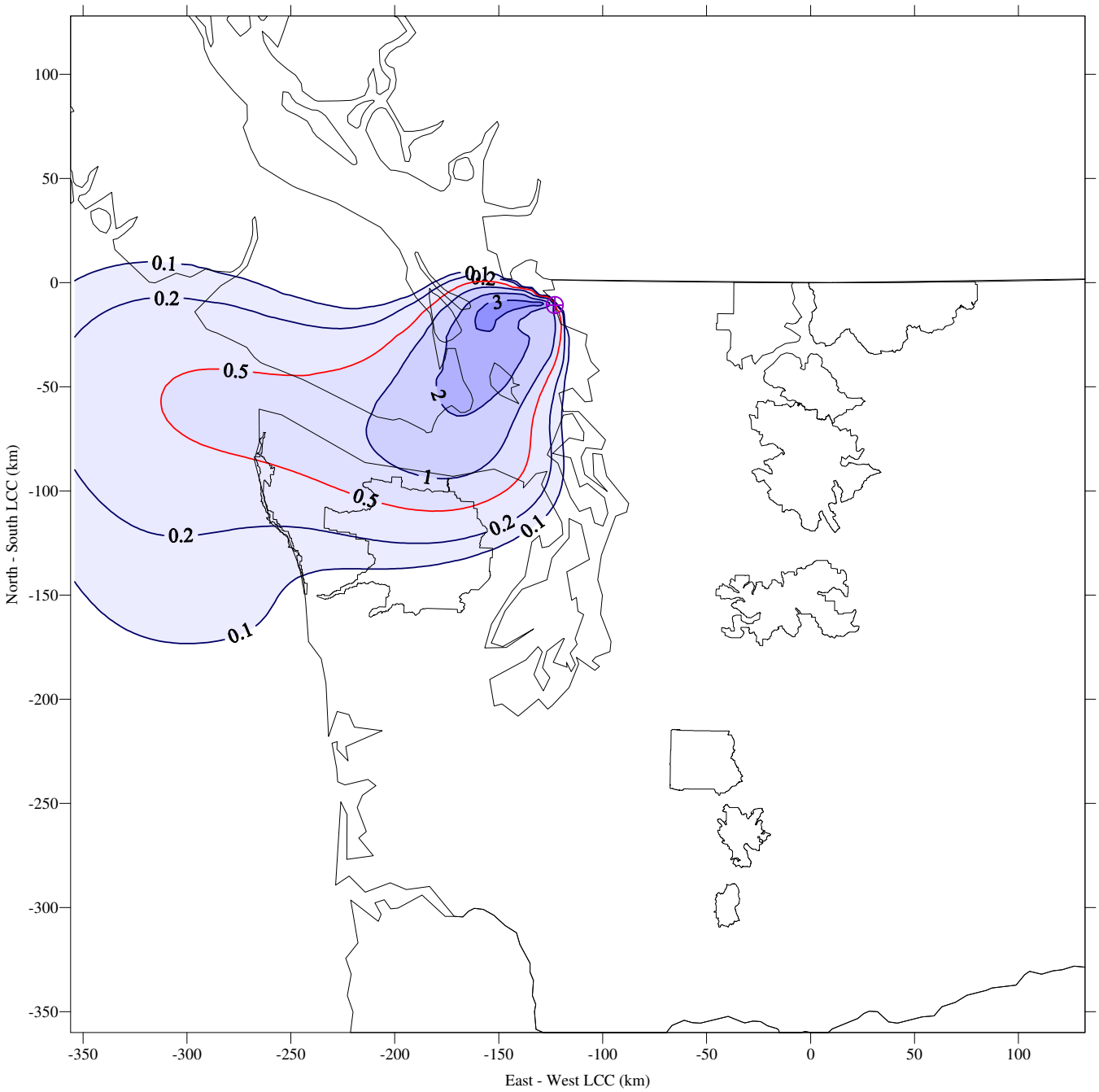



GEOMATRIX

BASELINE CASE DAILY DELTA HI (DV) FOR 2/22/2005
BP Cherry Point Refinery BART Determination Modeling
Blaine, Washington

Project No.
12966.000.0

Figure
**5-5**




GEOMATRIX

BART CASE DAILY DELTA HI (DV) FOR 2/22/2005
BP Cherry Point Refinery BART Determination Modeling
Blaine, Washington

Project No.
12966.000.0

Figure
**5-6**